Arnold Schwarzenegger
Governor

INDUSTRY-SPECIFIC REPORTING PROTOCOL: GUIDANCE FOR ENTITY-WIDE REPORTING OF GREENHOUSE GASES PRODUCED BY ELECTRIC POWER GENERATORS AND ELECTRIC UTILITIES

PIER FINAL PROJECT REPORT

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Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), annually awards up to $62 million to conduct the most promising public interest energy research by partnering with Research, Development, and Demonstration (RD&D) organizations, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grant Program
- Energy-Related Environmental Research
- Energy Systems Integration Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies

What follows is the final report for the Utility/Power Producer Specific GHG Reporting Protocol project, contract number 500-02-004, MR-03-23, conducted by the California Climate Action Registry. The report is entitled *Industry-Specific Reporting Protocol: Guidance for Entity-Wide Reporting of Greenhouse Gases Produced by Electric Power Generators and Electric Utilities.* This project contributes to the Energy-Related Environmental Research program.

For more information on the PIER Program, please visit the Energy Commission's Web site www.energy.ca.gov/pier/ or contract the Energy Commission at (916) 654-4628.

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Abstract

Building on its General Reporting Protocol, the California Climate Action Registry created a greenhouse gas (GHG) reporting protocol that enables electric power generators and electric utilities to report their annual, entity-wide inventory of GHG emissions. *Industry-Specific Reporting Protocol: Guidance for Entity-Wide Reporting of Greenhouse Gases Produced by Electric Power Generators and Electric Utilities* identifies methods to report emissions from stationary combustion, electric power generation processes, and fugitive emissions from the transmission and distribution of electricity. Additionally, this protocol provides guidance on calculating efficiency metrics that provide a normalized measure of environmental performance between companies.

Keywords: greenhouse gas, reporting protocol, emissions, fugitive emissions, efficiency metrics, climate change

Executive Summary

Introduction

The California Climate Action Registry (Registry) was established by California statute as a nonprofit voluntary registry for greenhouse gas (GHG) emissions. The purpose of the Registry is to help companies and organizations with operations in the state establish GHG emissions baselines against which any future GHG emission reduction requirements may be applied.

To enable registration, the Registry developed a General Reporting Protocol (GRP) to give general guidance to emitters with respect to reporting greenhouse gas (GHG) emissions in a consistent, credible, transparent manner. The assumption is that better knowledge of GHG emissions will lead to better management practices and reduced emissions.

The GRP provides solid guidance for general sources of GHG emissions, but it cannot provide specific guidance for each industry that produces GHG emissions within the state. Thus, the Registry plans to develop industry-specific reporting protocols that facilitate reporting of complete, consistent, comparable, accurate and transparent data for key industries.

One such industry is that of electric power generation and delivery. Approximately 16% of the state's CO_2 emissions are from utilities and power producers, and the electricity sector will continue to be a major source of GHG emissions over time.

Purpose and Project Objectives

This purpose of this project was to identify areas in the GRP that lacked specific guidance for utilities and power producers, and to provide clarity and specificity for these reporters. The resulting protocol is consistent with the GRP, and provides clear guidance for electric utilities/power producers in reporting GHG emissions in a credible, consistent, and transparent manner.

The project approach was, through a literature review of current reporting initiatives, to identify issues and guidance relevant to electric utilities and/or power generators. Over a period of nine months, the Registry and the help of a diverse workgroup of technical, economic, and policy experts, identified, discussed, and resolved issues to support GHG accounting.

Project Outcomes

At the end of the process, the Workgroup successfully met its objectives, namely:

- Identified key GHG accounting issues specific to the power and utility sectors.
- Evaluated existing relevant power/utility sector guidance developed or being developed by various entities (e.g., U.S. Environmental Protection Agency (EPA), Institute of Electrical Engineers (IEEE), World Resources Institute/World Business Council for Sustainable Development (WRI/WBCSD) GHG Protocol) for appropriateness of use by the Registry.
- Recommended appropriate emission factors and calculation methodologies.

- Collaborated with other Registry workgroups and relevant organizations to harmonize accounting principles.
- Considered viewpoints from a variety of stakeholders through the workgroup, sub-workgroups, expert reviewer, technical advisory, and public comment processes to produce a high-quality power/utility protocol (PUP).
- Created new policy guidance as necessary to meet the needs of the Registry.
- Presented a final draft protocol to the Registry's Board for their consideration in October 2004.
- Developed a reporting methodology, supportive of the Registry's existing General Reporting Protocol and Certification Protocols, that enables the complete, consistent, transparent, and accurate reporting of annual, entity-wide GHG emissions from the power and utility sectors.
- Achieved consistency with international GHG accounting guidelines.
- Identified relevant issues related to accounting for project-based emission reductions, which will be fully addressed in subsequent work groups.

Conclusions

There is a considerable amount of technical analysis of GHG emissions from the power sector, but this is a strong first effort to provide a methodology for calculating and reporting entity-wide emissions. Although most power/utility company emissions come from stationary combustion activities, it remains important and meaningful to provide a full accounting of their organization's emissions, including those from activities such as mobile sources, processes, and from fugitive emissions.[1] Each area of emissions contributes to the global greenhouse.

The workgroup approach helps to develop a document that is workable for a number of organizations, and presents a transparent way of developing reporting guidance.

Given the number of international reporting initiatives forming, it is important to maintain as much consistency as possible with international GHG accounting practices.

Feedback on the protocols through the various review processes helped identify areas for improvement; on the whole, comments were supportive of the proposed methodologies, and suggested refinements or further clarifications. With this support, the workgroup presented the protocols to the Registry's Board in October 2004 and received the Board's approval. Thus, all eligible Registry reporters are required to use the protocols to report their emissions starting with those emitted in 2005; and they can also use the protocols to report for previous years'

1 The Registry defines emissions as follows: *Stationary combustion* emissions are those produced through burning of fuels to generate electricity, steam, or heat; *mobile combustion* emissions are those produced through burning of fuels by transportation devices such as cars, trucks, airplanes, and vessels; *process emissions* are those generated from manufacturing or generation processes such as cement or ammonia production or sulfur dioxide scrubbing; *fugitive emissions* are intentional and unintentional releases of GHGs from joints, seals, gaskets, etc.

reporting. The protocols will be available at the California Climate Action Registry Web site, at www.climateregistry.org.

Recommendations

Establishing an entity-wide inventory is an essential first step to measuring and subsequently managing GHG emissions. As a follow-on effort, the Registry should also undertake an effort to begin to quantify the impact of renewable energy and energy efficiency projects on reducing or avoiding GHG emissions. With this guidance in place, there will be an additional incentive for companies to undertake and document such projects and their accompanying reductions in GHG emissions.

Benefits to California

Development of industry-specific reporting protocols for electric utilities and/or power generators will facilitate near-term reporting of GHG emissions, which in turn will help these large emitters identify internal inefficiencies and needed improvements. Such improvements will help to increase energy efficiency, provide significant cost and energy savings, and help prevent the negative effects of climate change on California's resources and citizens.

1.0 Introduction

1.1. Background and Overview

The California Climate Action Registry (Registry) was established by California statute as a nonprofit voluntary registry for greenhouse gas (GHG) emissions. The purpose of the Registry is to help companies and organizations with operations in the state establish GHG emissions baselines against which any future GHG emission reduction requirements may be applied.

The Registry encourages voluntary actions to increase energy efficiency and decrease GHG emissions. Using any year from 1990 forward as a base year, participants can record their GHG emissions inventory. The State of California, in turn, will offer its best efforts to ensure that participants receive appropriate consideration for early actions in the event of any future state, federal, or international GHG regulatory scheme. Registry participants include businesses, nonprofit organizations, municipalities, state agencies, and other entities.

To enable registration, the Registry developed a General Reporting Protocol (GRP) to give general guidance to emitters with respect to reporting GHG emissions in a consistent, credible, transparent manner. The assumption is that better knowledge of GHG emissions will lead to better management practices and reduced emissions.

The GRP provides solid guidance for general sources of GHG emissions, but it cannot provide specific guidance for each industry that produces GHG emissions within the state. Thus, the Registry is developing industry-specific reporting protocols that facilitate reporting of complete, consistent, comparable, accurate, and transparent data for key industries.

One key industry is that of electric power generation and delivery. Approximately 16% of the state's CO_2 emissions are from utilities and power producers, and the electricity sector will continue to be a major source of GHG emissions over time. The state's largest electric companies are Registry participants (Calpine, Pacific Gas &Electric, Southern California Edison, San Diego Gas & Electric, Anaheim Public Utilities, Burbank Water & Power, Los Angeles Department of Water & Power, and the Sacramento Municipal Utility District, as of October 2004), and requested additional guidance from the Registry on GHG reporting issues specific to the electricity sector. This project generated an appendix to the Registry's GRP that provides guidance for the reporting and certification of annual, entity-wide GHG emissions inventories by electric power generators and electric utilities.

In the electric power fuel cycle, GHGs are emitted in: (1) the production and transport of fuels and other raw materials used by electric generators, (2) the handling of fuels and other raw materials fed to boilers, (3) other processes at, or associated with, generating plants, (4) the production, disposal and utilization of waste materials, and (5) the transmission, distribution and utilization of the electricity generated. If companies are to utilize management tools based on climate-constraint, any action, even the installation of pollution control equipment, must be assessed to determine how it will affect GHG emissions.

As previously stated, all of the state's largest electric companies are already participants in the Registry and are working to inventory their total emissions. Companies believe that creating a GHG emissions inventory will increase their understanding of GHG emissions associated with electricity generation, such that they can manage and reduce the emissions more effectively. However, this sector lacks detailed guidance for reporting GHGs in a consistent manner.

The Registry, in collaboration with the World Resources Institute and other states, determined that the electricity sector is grappling with this issue elsewhere. Also, conversations with electricity industry company representatives led the Registry to believe that additional sector participation would be delayed without specific and consistent guidance for GHG reporting guidelines.

Thus, the Registry determined to develop industry-specific reporting protocols for electric utilities and/or power generators to facilitate near-term reporting of GHG emissions. More specifically, this project sought to identify areas in the GRP lacking specific guidance for utilities and power producers and provide clarity and specificity for these reporters. The resulting protocol must be consistent with the GRP, but provide clear guidance for electric utilities/power producers in reporting GHG emissions in a credible, consistent, and transparent manner.

The Registry anticipated that topics to be addressed would include: policy guidance to assist in clarifying organizational boundaries; accounting for mergers; calculation methodologies and emission factors appropriate to the power sector; industry metrics and other relevant issues. In this effort, the Registry did not address issues related to reporting emissions-reduction projects from electric power generation, transmission, and distribution.

1.2. Project Objectives

In conducting this effort, the Registry identified the following procedural and policy objectives:

1.2.1. Process Objectives

- Identify key GHG accounting issues specific to the power and utility sectors.
- Evaluate existing relevant power/utility sector guidance developed or being developed by various entities (e.g., U.S. Environmental Protection Agency (EPA), Institute of Electrical Engineers (IEEE), World Resources Institute/World Business Council for Sustainable Development (WRI/WBCSD) GHG Protocol) for appropriateness of use by the Registry.
- Recommend appropriate emission factors and calculation methodologies.
- Collaborate with other Registry workgroups and relevant organizations to harmonize accounting principles.
- Consider viewpoints from a variety of stakeholders through the workgroup, sub workgroup, expert reviewer, technical advisory, and public comment processes to produce a high-quality power/utility protocol (PUP).
- Create new policy guidance as necessary to meet the needs of the Registry.

- Present a final draft protocol to the Registry's Board for their consideration by October 2004.

1.2.2. Protocol Objectives

- Develop a reporting methodology, supportive of the Registry's existing General Reporting Protocol and Certification Protocols, that enables the complete, consistent, transparent, and accurate reporting of annual, entity-wide GHG emissions from the power and utility sectors.
- Strive for consistency with international GHG accounting guidelines.
- As relevant, identify issues related to accounting for project-based emission reductions, which will be fully addressed in subsequent work groups.

1.3. Report Organization

Section 2 covers the project approach, Section 3 discusses project outcomes, and Section 4 offers conclusions and recommendations. The draft Power/Utility Reporting Protocol is included in Appendix C, and the draft Power/Utility Certification Protocol is included in Appendix D. The protocols will also be available at the California Climate Action Registry Web site, at www.climateregistry.org.

2.0 Project Approach

Prior to beginning work on this project, the Registry held a scoping meeting, attended by technical experts and interested parties to help identify GHG accounting issues needing resolution. This meeting confirmed a need to undertake this effort, and helped identify a first list of issues. After obtaining funding from this PIER grant and other funders, the Registry formulated the following project approach and workplan.

2.1. Task 1: Identify Current Best Practices in GHG Emissions Reporting

Our first task, working with a facilitator approved by the Registry's Technical Advisory Committee, was to conduct a literature review of current reporting initiatives and identify issues and guidance relevant to electric utilities and/or power generators.

2.2. Task 2: Form Utility/Power Producer Workgroup

We next formed a volunteer workgroup of technical, economic, and policy experts. Working with our Technical Advisory Committee, we identified key stakeholders and perspectives to include on the workgroup. We issued invitations to a small number of organizations, making every effort to represent a variety of perspectives among the participants– including representatives from California and non-California electric utilities, power generators, Registry and non-Registry members, environmental organizations, regulatory agencies, trade associations, and technical experts, including those from the World Resources Institute, the organization leading an international effort to develop GHG accounting standards. We also hired a facilitator for this process, to help manage the workgroup calls and provide technical support. Lastly, to support communication among the workgroup we created a password-protected Web page to store and archive project documents, as well as a Listserve for the workgroup members.

Over a period of six months we held a series of conference calls to identify, discuss and resolve issues to support GHG accounting. We presented an initial list of key issues to the workgroup as a starting point for discussion, which was further refined through the workgroup's discussions. Working with the ground rules and objectives of both the process and for the products—namely to consider broad perspectives, build on existing work, and make necessary decisions to ensure the finished document is complete and comprehensive.

Key to beginning work also was establishing a Workgroup Decision Rule. As a group, we agreed to abide by the following rules of order:

- Workgroup member organizations were welcome to suggest additional workgroup members to add expertise and perspective to the workgroup at any time. All recommendations were considered by the entire Workgroup and pursued by the Registry.
- Organizations participating in the Workgroup process could designate one or more representatives to participate in Subgroups, but had to designate a single lead contact that represented the organization on the Workgroup conference calls.
- In making decisions, it was the Registry's hope that the protocol workgroup process would facilitate consensus on all of the issues raised during the protocol development process. However, in instances where consensus could not be achieved despite reasonable efforts to do so, then decisions were made by majority rule (one vote per organization).
- Each workgroup members could use any of the following levels to make individual decisions (and ultimately group decisions) on issues:
    - Agree with proposal as presented
    - Mixed feelings but willing to accept proposal as presented
    - Disagree with proposal as presented
- In the event any workgroup member disagreed with the majority decision, the disagreement, reason for disagreement, and suggested alternative (if any) was recorded.
- Where outside experts were called upon to provide input to the Registry workgroup, but were not members of the workgroup, the experts were asked to make recommendations, but were not eligible to vote on policy decisions.

2.3. Task 3: Draft Sector-specific Protocol Recommendations

After a series of weekly discussions on key issues over a period of six months, we developed first drafts of (1) an electric power reporting protocol, and (2) a certification protocol. These documents were circulated among the workgroup for review; then the workgroup began a series of consultations to obtain additional feedback on the drafts. The drafts were first circulated to peer reviewers in the power and utility sectors. They next were reviewed by the Registry's Technical Advisory Committee for consistency with the Registry's other protocols. The final round of review was conducted by the

California Energy Commission on behalf of the State of California. As part of the State's review, the Energy Commission hosted a public comment period and a public workshop on the drafts and provided the Registry and workgroup with public feedback from this process.

2.4. Task 4: Final Protocol Recommendations

At the end of the public comment period (October 1, 2004), the workgroup incorporated final comments from the general public and presented final draft protocols to the Registry's Board on October 21, 2004. The Board approved the protocols, and these protocols are required for reporters to the California Climate Action Registry, beginning with emissions produced during the year 2005. Reporters have expressed their interest in using the guidance for previous years as well (although they are not required to do so).

3.0 Project Outcomes

In this phase of the project, we successfully completed the expected task of completing draft protocols that enable standardized and accurate entity-wide reporting of direct and indirect GHG emissions produced by the electric power and utility sectors, to accompany the General Reporting and Certification Protocols.

With the help of the workgroup and technical experts, we drafted documents that will support this effort. We believe the documents address and resolve the significant issues needed for electric utilities and power generators to report their annual inventories of GHG emissions.

The project will continue beyond this phase to obtain adoption of the protocols by the Registry's Board. The final test will be upon implementation of these reporting and certification guidelines over time. The goal of measuring GHGs is to improve environmental performance and result in fewer GHGs emitted over time.

3.1. Process Outcomes

More specifically, the outcomes of this effort include the following key elements:

- *Identified key GHG accounting issues specific to the power and utility sectors.*

  We began work with a list of relevant GHG accounting issues and further refined this document. The initial list of issues is included as Appendix A. The workgroup grouped these items into five subcategories: (1) Direct Combustion, (2) Fugitive Emissions, (3) Indirect Emissions, (4) Certification, and (5) Cross-Cutting Issues. Each subcategory was the focus of approximately one month's discussion. The final issues identified are resolved in the draft protocols, included in Appendices C and D.

- *Evaluated existing relevant power/utility sector guidance developed or being developed (by U.S. EPA, IEEE, WRI/WBCSD GHG Protocol, etc.) for appropriateness of use by the Registry.*

We conducted a literature review and identified relevant resources to inform our project. These resources are identified on the References list in the protocol. When we began the project we were aware of documents such as the GHG Protocol (published by the World Resources Institute and the World Business Council for Sustainable Development), as well as draft GHG standards being developed by the International Standards Organization. We also expanded our search to review and include existing environmental regulations and their associated reporting forms that power/utility companies are required to complete. Primary among these are the U.S. EPA's 40 CFR Part 75, as well as a number of Federal Energy Regulatory Commission (FERC), Security and Exchange Commission (SEC), and Energy Information Administration (EIA) forms.

- *Recommend appropriate emission factors and calculation methodologies.*

  The workgroup spent a considerable amount of time evaluating appropriate emission factors. For fuels, we identified and selected calculation methodologies and emissions factors from the U.S. EPA and U.S. Department of Energy (DOE). For this portion of the project, there was no shortage of available sources—our task was determining which sources were the most accurate and most reliable for calculating GHG emissions.

  We also sought to recommend on the best emission factor for calculating purchases of electricity. After lengthy discussion, review of numerous data sources, and consultation with technical experts, the consensus was to recommend the use of emission factors from U.S. EPA's eGRID database. The eGRID numbers provide a nationally calculated source that is updated regularly, and that considers the impact of electricity imports into a state when determining an emission factor.

- *Collaborated with other Registry workgroups and relevant organizations to harmonize accounting principles.*

  Concurrent with developing this industry-specific protocol for the power/utility sectors, the Registry was also engaged in an effort to develop guidance for forest sector companies and forest projects. As a result, this workgroup collaborated with the forestry workgroup to ensure consistency with respect to accounting for emissions from combustion of biomass. We also collaborated with the Center for Resource Solutions to coordinate on the definitions of other renewable energy sources.

  Through the participation of the World Resources Institute in the workgroup, we were also able to maintain consistency with leading international GHG accounting efforts in our reporting decisions. Specifically, this desire to maintain harmonized accounting principles affected our definitions of direct and indirect emissions, as well as the criteria we selected for establishing organizational, operational, and geographic boundaries.

- *Considered viewpoints from a variety of stakeholders through the workgroup, sub-workgroup, expert reviewer, technical advisory, and public comment processes to produce a high-quality PUP.*

  In every phase of review, we sought a variety of perspectives. As already mentioned, we devised our workgroup to include industry, government, academic, and environmental perspectives. The complete list of workgroup members and other contributors is included in Appendix B. In addition, we sought technical advisors who would provide technical guidance to supplement the expertise of the workgroup (e.g., from the Center for Resource Solutions, Lawrence Berkeley National Laboratory, U.S. Environmental Protection Agency). Lastly, we solicited feedback from over 100 expert reviewers from across the spectrum of the electric power industry, including generators, merchants, large consumers, technology developers, environmental organizations, government, and more. We addressed and incorporated the relevant feedback to help us develop the protocols.

- *Created new policy guidance as necessary to meet the needs of the Registry.*

  For many business areas of the electric power sector, generation and quantification of GHGs is based on relatively common measurement processes and calculation methodologies. We were able to identify and resolve stationary combustion methods without much disagreement. However, we had a harder task in determining calculation methods for process and fugitive emissions within the power sector.

  For process emissions, we identified sources of GHGs, namely carbon dioxide (CO_2) from sulfur dioxide (SO_2) scrubbing, hydrogen production, and the use of clean coal technologies. We were only able to identify calculation methodologies for the SO_2 scrubbing process.

  For fugitive emissions, we readily identified sources of GHGs (including CH_4 leaks from pipelines, valves, and other T&D equipment). However, we also had to identify guidance to calculate CO_2 emissions as a result of methane leaks from underground pipelines that oxidize in the soil. Lastly, we also worked to identify a system-wide approach to calculating fugitive emissions, but were unable to settle on a method with enough rigor. During the public review process, stakeholders from the natural gas industry advised the workgroup that the natural gas guidance proposed in the protocol was not appropriate for non-utility operations, but currently did encompass the natural gas transmission industry. Based on this feedback, the workgroup revised the scope of the protocol to address only electric power generation, transmission, and distribution issues, and will continue to work on refining natural gas accounting methodologies that are appropriate for both natural gas transmission and distribution. This new effort is expected to be completed by the end of 2005.

- *Presented a protocol to the Registry's Board for their consideration by October 2004.*

  We met this timeline, which ensured that the new guidance would be available for reporters as of January 1, 2005. Following review by technical experts, we provided revised drafts to the State of California for further examination by state experts. A public workshop to discuss the draft protocols was held on September 9, 2004 in Sacramento, hosted by the California Energy Commission; the State provided feedback to the Registry and the Workgroup in October 2004. The final steps were to address and incorporate the guidance received from the State and the public, and forward the documents to the Registry's Board for their consideration on October 21, 2004.

3.2. Protocol Outcomes

- *Developed a reporting methodology, supportive of the Registry's existing General Reporting Protocol and Certification Protocols, which enables the complete, consistent, transparent, and accurate reporting of annual, entity-wide GHG emissions from the power and utility sectors.*

  The attached draft documents represent our best effort to provide a reporting methodology that enables the reporting of all significant sources in a consistent manner over time. It lays out calculations and methodologies that can be repeated with the same results, by anyone reading or implementing the protocols. Also, through the guidance laid out in the Power/Utility Certification Protocol, we provide indications to third-party organizations approved to review and assess the power/utility annual emission reports what criteria should be used to make final determinations. For both documents we reviewed the protocols for consistency with the GRP and GCP. The final test will be upon use and implementation of the protocols by companies reporting to the California Climate Action Registry, and it will likely be necessary to continue to refine the guidance over time. However, the workgroup and reviewers feel this is a commendable foundation; and experience will inform any subsequent refinements to the guidance.

  In this effort, the workgroup also identified some gaps in available guidance that should be addressed in the GRP and GCP—for instance, the reporting of emissions from cogeneration facilities. Although many of these are owned and/or operated by companies in the power sector, they are also frequently used by other large, industrial users, for instance. As such, this guidance properly belongs in the GRP. The same is true for many mobile sources.

- *Strove for consistency with international GHG accounting guidelines.*

  As much as possible, we have maintained consistency with international GHG accounting guidelines. There are some elements of the Registry program, included in California law, that dictate some differences with international GHG accounting guidelines—notably, our requirement to offer geographic reporting

(California emissions or U.S. emissions); whereas, international guidelines direct all reporting to be based on legal or financial relationships.

- *As relevant, identified issues related to accounting for project-based emission reductions, which will be fully addressed in subsequent work groups.*

  Through discussions, the workgroup identified a number of issues to be considered in developing guidelines for calculating emissions from reduction projects in the power sector. These include the quantification of energy efficiency projects, and the purchase and sale of renewable energy.

4.0 Conclusions and Recommendations

4.1. Conclusions

- There is a considerable amount of technical analysis that has been completed to date. However, there is limited work done and tested that provides corporate level reporting of GHGs. Also, for power/utility companies, while most of their emissions come from stationary combustion activities, it remains important and meaningful to provide a full accounting of their organization's emissions, including those from activities such as mobile sources, processes, and from fugitive emissions.

- Using a workgroup to complete this effort is an effective method. This ensures the final documents are workable for a variety of organizations. Also, it is essential to involve a variety of perspectives in developing this new type of guidance to make sure that the final product considers both the practicalities and the priorities of publicly reporting GHG emissions.

- Given the number of international reporting initiatives forming, it is also important to maintain consistency with international GHG accounting practices to help decrease the complexity and burden of reporting under voluntary schemes.

4.2. Recommendations

Establishing an entity-wide inventory is an essential first step to measuring and subsequently managing GHG emissions. Next steps should include programming the guidance into the Registry's automated reporting tool (CARROT), to complete the ability for companies to report to the Registry. As a follow-on effort, the Registry should also undertake an effort to begin to quantify the impact of renewable energy and energy efficiency projects. With this guidance in place, it will provide additional incentives for companies to undertake and document such projects and their accompanying reductions in GHG emissions.

4.3. Benefits to California

Development of industry-specific reporting protocols for electric utilities and/or power generators will facilitate near-term reporting of GHG emissions, which in

turn will help these large emitters identify internal inefficiencies and needed improvements. Such improvements will help to increase energy efficiency, provide significant cost and energy savings, and help prevent the negative effects of climate change on California's resources and citizens.

Already, with the guidance in draft form, we have gotten feedback from our current reporters that this will dramatically increase the transparency, consistency, and accuracy with which they report. Also, by requiring metrics to provide comparability between companies in the same sector, companies will be better able to gauge the carbon intensity of their activities and prioritize actions to reduce their total GHGs—thereby improving the environmental quality of the products delivered to California citizens.

Appendix A

Power/Utility Protocol (PUP) Key Issues for Consideration

Direct Combustion Emissions

Direct emissions are those from sources owned or controlled by the reporting organization.

- Sources. Besides fuel used for combustion, what are the GHG emission sources from direct combustion?
- Calculations. Are mass-based calculations the best way to calculate direct emissions?
    - For companies that have CEMs, should this data be provided instead of/in addition to mass-based calculations?
    - What is the best way to calculate emissions from cogen/CHP?
- Emission Factors. The GRP provides some CH_4 and N_2O emission factors for stationary combustion, by broad fuel type (coal, petroleum, natural gas, wood). Are more specific guidance and emission factors needed? If so, what calculation methodologies are appropriate?

Direct Fugitive Emissions

Fugitive emissions are intentional and unintentional releases of GHGs from joints, seals, gaskets, etc.

- Sources
    - In addition to CH_4, are there other fugitive GHGs from natural gas transmission and distribution?
    - What fugitive emissions are produced during fuel storage/handling/disposal?
    - Besides SF_6, are there any other fugitive gases from electric transmission and distribution?
    - Is additional guidance needed for fugitive emissions from utility operations, e.g., HFCs from air conditioning?
- Calculations.
    - What is the best way to calculate each type of fugitive emission? e.g., is the EPA method to quantify SF_6 the only method/best method that exists?

Indirect Emissions

Indirect emissions are those that are a consequence of the actions of a reporting entity, but are produced by sources owned or controlled by another entity.

- Emission Factors. Currently, the GRP uses EIA state-specific emission factors to calculate indirect emissions. Should we instead require region, state or utility-specific emission factors?
    - Renewable Energy.
        - How do we account for green power purchases?
        - How do we account for purchased RECs in an entity inventory?

- Boundaries. How should purchased power boundaries be drawn – both domestically and internationally?
- Measurement. How should generators/utilities account for the electricity used by their own operations when they do not separately meter their own electricity consumption?

Cross Cutting Issues

- Ownership Criteria. The General Reporting Protocol (GRP) allows organizations to report using management control and/or equity share in defining their entity wide boundaries. Are the criteria outlined in the GRP for reporting management control and/or equity share appropriate for power/utilities?
- Contracts.
    - Should power purchased through PPAs be counted as direct emissions?
    - Absent GHG regulation, can contracts transfer ownership of GHG emissions?
- Metrics.
    - What output-based metrics should be required for the power utility sector?
        - lbs CO_2e/MWh – and/or:
            - by fuel type?
            - fossil fuel only?
            - total energy?
    - Are there metrics that should *not* be used?
    - Should fugitive emissions have a separate metric?

Certification

Certification is the process used to ensure that a given participant's greenhouse gas emissions inventory has met a minimum quality standard and complied with the Registry's procedures and protocols for calculating and reporting GHG emissions.

- Criteria. What are the criteria for certifiers to assess the accuracy of inventories reported by companies in the power/utility sectors?
- Documentation.
    - Is data reported to regulatory agencies admissible and appropriate for reporting GHG emissions? If so, does this include data reported to FERC? ISO? CEC? DOT?
    - For net sales and purchases, can the Certifier (and the CEC) open wholesale trading books?
    - Can the Certifier open documents with attorney-client privilege?
- Conflict of Interest.

"Parking Lot:" Issues to be resolved in a Project-Level Reporting Protocol

Demand-Side Management.

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Appendix C to the General Reporting Protocol: Power/Utility Reporting Protocol

Reporting Entity-Wide Greenhouse Gas Emissions Produced by Electric Power Generators and Electric Utilities

Table of Contents

Acknowledgements

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Acronyms and Abbreviations

API	American Petroleum Institute
C	carbon
CARROT	Climate Action Registry Reporting Online Tool
CEC	California Energy Commission
CEM	Continuous Emissions Monitor
CH_4	methane
CO_2	carbon dioxide
DOE	U.S. Department of Energy
eGRID	Emissions & Generation Resource Integrated Database
EIA	Energy Information Administration (U.S. DOE)
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GHGs	greenhouse gases
GRP	General Reporting Protocol
GWP	Global Warming Potential
HFC	hydrofluorocarbon
kWh	kilowatt-hour
Lb.	pound
MMBtu	million British thermal units
MWh	Megawatt-hour
N_2O	nitrous oxide
NERC	North American Electric Reliability Council
PFC	perfluorocarbon
PUP	Power/Utility Protocol
Registry	The California Climate Action Registry
SEC	Securities & Exchange Commission
SF_6	sulfur hexafluoride
T&D	transmission and distribution
WRI	World Resources Institute

Key Power/Utility Protocol Terms

Term	Definition	Source
Boiler	A device for generating steam for power, processing, or heating purposes or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes in the boiler shell. This fluid is delivered to an end-use at a desired pressure, temperature, and quality.	Power Marketing Association (PMA)
Bulk Electric System	A term commonly applied to the portion of an electric utility system that encompasses the electrical generation resources and bulk transmission system.	North American Electric Reliability Council (NERC)
Bulk Transmission	A functional or voltage classification relating to the higher voltage portion of the transmission system.	NERC
Capacity	The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment.	NERC
Capacity Factor	The ratio of the total energy generated by a generating unit for a specified period to the maximum possible energy it could have generated if operated at the maximum capacity rating for the same specified period, expressed as a percent.	NERC
Cogeneration	Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.	NERC
Combined Cycle	An electric generating technology in which electricity and process steam is produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.	NERC
Continuous Emission Monitoring System	CEM is the continuous measurement of pollutants emitted into the atmosphere in exhaust gases from combustion or industrial processes. CEM systems include: • An SO_2 pollutant concentration monitor. • A NO_x pollutant concentration monitor. • A volumetric flow monitor. • An opacity monitor. • A diluent gas (O_2 or CO_2) monitor. • A computer-based data acquisition and handling system (DAHS) for recording and performing calculations with the data.	U.S. Environmental Protection Agency (EPA)
Demand	The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. Demand should not be confused with Load.	NERC
Demand-Side Management	The term for all activities or programs undertaken by an electric system or its customers to influence the amount or timing of electricity use.	NERC

Term	Definition	Source
De minimis	A quantity of GHG emissions from one or more sources, for one or more gases, which, when summed equal less than 5% of an organization's total emissions.	
Direct monitoring	Direct monitoring of exhaust stream contents in the form of continuous emissions monitoring (CEM) or periodic sampling.	World Resources Institute (WRI)
Distribution System	The low voltage system of power lines, poles, substations and transformers, directly connected to homes and businesses. Your Distribution Company is the electric utility that delivers electricity to your home or business over these wires. The utility will read your meter, maintain local wires and poles and restore your power in the event of an outage.	Center for Resource Solutions (CRS)
Electric Plant (Physical)	A facility containing prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or fission energy into electric energy.	PMA
Electric System Losses	Total electric energy losses in the electric system. The losses consist of transmission, transformation, and distribution losses between supply sources and delivery points. Electric energy is lost primarily due to heating of transmission and distribution elements.	NERC
Electric Utility	A corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for the generation, transmission, distribution, or sale of electric energy primarily for use by the public and is defined as a utility under the statutes and rules by which it is regulated. Types of Electric Utilities include investor-owned, cooperatively owned, and government-owned (federal agency, crown corporation, state, provincials, municipals, and public power districts).	NERC
Electrical Energy	The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).	NERC
Federal Energy Regulatory Commission (FERC)	A quasi-independent regulatory agency within the Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification.	PMA
Fuel Totalizer	A meter that sums the volume or mass of fuel used (rather than the flow rate of fuel).	
Fugitive Emissions	Unintended leaks of gas from the processing, storage, transmission, and/or transportation of fossil fuels.	U.S. Department of Energy (DOE)
Generation (Electricity)	The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatthours (kWh) or megawatthours (MWh).	NERC
Geothermal Plant	A plant with steam turbines powered by either steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the earth. The energy is extracted by drilling and/or pumping.	PMA

Term	Definition	Source
Gross Generation	The electrical output at the terminals of the generator, usually expressed in megawatts (MW).	NERC
Heating value	The amount of energy released when a fuel is burned completely. Care must be taken not to confuse higher heating values (HHVs), used in the US and Canada, and lower heating values, used in all other countries.	WRI GHG Protocol
Independent Power Producers (IPP)	As used in NERC reference documents and reports, any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term may include, but is not limited to, cogenerators and small power producers and other nonutility electricity producers, such as exempt wholesale generators who sell electricity.	NERC
Kilowatt-Hour	A standard unit of measure of electrical energy One kilowatt-hour is equal to 1,000 watt-hours. The total number of kilowatt-hours charged to your bill is determined by your electricity use. For example, if you used a 100-watt light bulb for 10 hours, you would be billed for one kilowatt-hour (100 watts x 10 hours= 1,000 watt-hours). The average home in the United States uses 750 kWh/ month.	
Liquefied Natural Gas	Natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.	U.S. DOE Energy Information Administration (EIA)[1]
Load	An end-use device or customer that receives power from the electric system. Load should not be confused with Demand, which is the measure of power that a load receives or requires. See Demand.	NERC
Mains	Physical system through which liquid or gaseous fuels are transported.	
Megawatt-Hour	One thousand kilowatt-hours or 1 million watt-hours.	
Metering	The methods of applying devices that measure and register the amount and direction of electrical quantities with respect to time.	NERC
Municipal Utility	A municipal utility is a non-profit utility that is owned and operated by the community it serves.	
Net Capacity	The maximum capacity (or effective rating), modified for ambient limitations, that a generating unit, power plant, or electric system can sustain over a specified period, less the capacity used to supply the demand of station service or auxiliary needs.	NERC
Net Energy for Load	The electrical energy requirements of an electric system, defined as system net generation, plus energy received from others, less energy delivered to others through interchange. It includes system losses but excludes energy required for storage at energy storage facilities.	NERC

[1] EIA. http://www.eia.doe.gov/oil_gas/natural_gas/info_glance/natural_gas.html

Term	Definition	Source
Net Generation	Gross generation minus station service or unit service power requirements, usually expressed in megawatts (MW) or megawatt hours (MWh).	NERC
North American Electric Reliability Council (NERC)	A not-for-profit company formed by the electric utility industry in 1968 to promote the reliability of the electricity supply in North America. NERC consists of nine Regional Reliability Councils and one Affiliate whose members account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. The members of these Councils are from all segments of the electricity supply industry — investor-owned, federal, rural electric cooperative, state/municipal, and provincial utilities, independent power producers, and power marketers. The NERC Regions are: East Central Area Reliability Coordination Agreement (ECAR); Electric Reliability Council of Texas (ERCOT); Mid- Atlantic Area Council (MAAC); Mid-America Interconnected Network (MAIN); Mid-Continent Area Power Pool (MAPP); Northeast Power Coordinating Council (NPCC); Southeastern Electric Reliability Council (SERC); Southwest Power Pool (SPP); Western Systems Coordinating Council (WSCC); and Alaskan Systems Coordination Council (ASCC, Affiliate).	NERC
Pipeline (Natural Gas)	A continuous pipe conduit, complete with such equipment as valves, compressor stations, communications systems, and meters, for transporting natural and/or supplemental gas from one point to another, usually from a point in or beyond the producing field or processing plant to another pipeline or to points of use.	EIA
Pipeline Fuel (Natural Gas)	Gas consumed in the operation of pipelines, primarily in compressors.	EIA
Power Pool	An association of two or more interconnected electric systems having an agreement to coordinate operations and planning for improved reliability and efficiencies.	PMA
Qualifying Facility (QF)	A cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by FERC pursuant to PURPA (See CFR, Title 18, Part 292).	PMA
Renewable Energy	Energy drawn from a source that is infinite or is replenished through natural processes. Such sources include the sun, wind, heat from the earth's core, biomass, and moving water.	California Energy Commission
Renewable Power	A power source other than a conventional power source, defined as power derived from nuclear energy or the operation of a hydropower facility greater than 30 megawatts or the combustion of fossil fuels, unless cogeneration technology…is employed in the production of such power.	California Energy Commission Renewable Energy Program: Overall Program Guidebook
Spot Purchases	A single shipment of fuel or volumes of fuel, purchased for immediate delivery or within one year. Spot purchases are often made by a user to fulfill a certain portion of energy requirements, to meet unanticipated energy needs, or to take advantage of low fuel prices.	PMA

Term	Definition	Source
Stocks	A supply of fuel accumulated for future use. This includes, but is not limited to, coal and fuel oil stocks at the plant site, in coal cars, tanks, or barges at the plant site, or at separate storage sites.	PMA
Storage	Energy transferred from one entity to another entity that has the ability to conserve the energy (i.e., stored as water in a reservoir, coal in a pile, etc.) with the intent that the energy will be returned at a time when such energy is more usable to the original supplying entity.	NERC
Substation	A facility for switching electrical elements, transforming voltage, regulating power, or metering.	NERC
Transformer	An electrical device for changing the voltage of alternating current.	PMA
Transmission (Electric)	An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.	NERC
Underground Gas Storage	The use of sub-surface facilities for storing gas that has been transferred from its original location. The facilities are usually hollowed-out salt domes, natural geological reservoirs (depleted oil or gas fields) or water-bearing sands topped by an impermeable cap rock (aquifer).	EIA
Vented Emissions	Releases to the atmosphere as a result of the process or equipment design or operational practices.	API Compendium
Wheeling Service	The movement of electricity from one system to another over transmission facilities of intervening systems. Wheeling service contracts can be established between two or more systems.	PMA
Wholesale Sales	Energy supplied to other electric utilities, cooperatives, municipals, and Federal and State electric agencies for resale to ultimate consumers.	PMA

Chapter 1: Introduction

This document, the Power Generation/Electric Utility Reporting Protocol (Power/Utility Protocol or PUP), is an appendix to the Registry's General Reporting Protocol (GRP). It provides reporting standards for how electric power generation and utility (electricity transmission and distribution) entities must compile, report, and certify their **entity-wide GHG emissions** to submit their annual emissions inventory to the Registry.

Many electric utilities also have natural gas operations, including natural gas storage, transmission and distribution. This protocol does not contain guidance for reporting the emissions from natural gas operations of electric utilities. The CA Registry intends to revise this protocol in the near future to include GHG accounting guidance for natural gas storage, transmission & distribution.

The GRP provides the framework for businesses, government agencies, and non-profit organizations to participate in the California Climate Action Registry (the Registry). It presents the principles, approach, methodology, and procedures required for effective participation in the Registry. The GRP is designed to support the complete, transparent, and accurate reporting of an organization's greenhouse gas (GHG) emissions in a fashion that minimizes the reporting burden and maximizes the benefits associated with understanding the connection between fossil fuel consumption, energy production, and GHG emissions in a quantifiable manner.

The GRP guides participants through the Registry's reporting rules, emissions calculation methodologies, and the Climate Action Registry Reporting Online Tool (CARROT). By joining the Registry, participants agree to report their GHG emissions according to the guidelines in the GRP and its appendices.

Additional guidance is also provided for some industries that require additional clarification to report their California- or U.S. emissions in a comparable, consistent, and accurate manner. Thus, the Registry has developed the Power/Utility Protocol for companies that generate or transmit electricity.

The GRP assumes the following. These assumptions are also true for this PUP:

- Participants are encouraged to report all six GHGs starting in year one, but may opt to limit their reports to only carbon dioxide (CO_2) emissions during the first three years of participation in the Registry. After the third year of Registry participation, participants are required to include all six GHGs (if applicable) in the annual Emission Report.
- Heat values are calculated using Higher Heating Values (HHV). Lower Heating Values (LHV) are provided in Annex X for comparison.
- Global Warming Potential is calculated using factors from the Intergovernmental Panel on Climate Change's Second Assessment Report (1996), consistent with international practice. Values from the Third Assessment Report (2001) are also provided for comparison.
- Participants may designate up to 5% of their total emissions as *de minimis*.

This document is divided into eleven chapters: Chapter 1 introduces the PUP, power/utility entity reporting, and discusses basic concepts and reporting criteria; Chapters 2-4 help power/utility entities establish their organizational, operational and geographic boundaries; Chapters 5-8 provide guidance to power/utility entities to quantify CA or U.S. emissions; Chapter 9 assists power/utility entities in quantifying and reporting industry-specific metrics; Chapter 10 provides guidance to power/utility entities on calculating de minimis emissions; and Chapter 11 provides guidance on optional reporting categories.

1.1 Eligibility

Use of the PUP is required for entities in the electric power and utility sectors when reporting entity-wide GHG emissions to the Registry. Power and utility entities are defined as those companies or facilities with the following codes in the North American Industry Classification System (NAICS)[2]:

2211 Electric Power Generation, Transmission and Distribution: This industry group is comprised of establishments primarily engaged in generating, transmitting, and/or distributing electric power. Establishments in this industry group may perform one or more of the following activities: (1) operate generation facilities that produce electric energy; (2) operate transmission systems that convey the electricity from the generation facility to the distribution system; and (3) operate distribution systems that convey electric power received from the generation facility or the transmission system to the final consumer.

1.2 Industries that Generate Power/Steam/Heat

Because numerous industrial sectors generate electricity, heat or steam for their own use and even for sale to outside entities, portions of the PUP should serve as a reference for quantifying emissions associated with these activities. For example, the section of the protocol that addresses direct combustion emissions associated with combined heat and power (CHP) operations may apply to numerous industries outside of the power utility industry that operate CHP.

[2] http://www.census.gov/epcd/www/naics.html

Chapter 2: Defining Organizational Boundaries

This chapter discusses the options and requirements for determining your organizational boundaries. This includes guidance for what you must report in your GHG Emission Report based on your ownership of different facilities.

2.1 Types of Organizational Relationships in Power/Utility Sectors

The electric power and utility sectors have a multitude of ownership and management control arrangements for power generation facilities, transmission & distribution assets for electricity and natural gas, as well as for the commodities themselves (electricity, steam, heat, and natural gas). These ownership scenarios are listed below:

1. *Full ownership* – There is one single owner of the asset.

2. *Co-ownership* –There is more than one owner of the asset with varying degrees of ownership and operational control (ranging from 1% to 99%).

3. *Majority owner and operational control of the facility* – In some cases, the operator of the assets has control of the facility.

4. *Minority owner but operational control of the facility* – In some cases, the operator of an asset may not have majority ownership of the facility.

5. *Operator of the facility, but no ownership share* – In some cases, an entity has operational control without any ownership share.

6. *Leasing* – The asset is leased for a discrete duration of time, with operational control resting with the lease holder.

7. *Joint Power Agreement* – There is more than one public agency owner of the asset with varying degrees of ownership and operational control (ranging from greater than zero to less than 100%).

When determining your organizational boundaries, you may report using either management control and/or equity share. Because of the number of joint ownership arrangements common in power generation, it is *strongly recommended* that you calculate and report your GHG emissions using the equity share method. Whichever method you choose, you must report using the same method for every facility.

2.2 Equity Share

When reporting using equity share, you document only your company's economic interest in an operation. Your equity share will usually be the same as your ownership percentage.[3]

In the electric power and utility sector, joint ownership of assets is commonplace. To clarify ownership (rights) and responsibilities (obligations), companies involved in joint operations draw up contracts specifying the distribution of ownership between the parties. Where such arrangements exist, companies each report their emissions according to ownership arrangements described in the contracts.

2.3 Management Control

[3] Language from the WRI/ WBCSD GHG Protocol Corporate Accounting and Reporting Standard (Revised Edition). http://www.ghgprotocol.org/standard/index.htm

Under the management control approach, a company accounts for 100% of the GHG emissions from operations over which it has control. You should refer to the GRP if you have any questions as to whether or not you can establish management control.

If you choose to report using the management control method, you must also provide documentation from any partners with whom you share ownership in a facility acknowledging who will be reporting the emissions from that facility.

Table 2.1 demonstrates how emissions would be reported under the different ownership scenarios using equity share and/or management control approaches.

Table 2.1 Reporting Emissions Under Equity Share and Management Control Approaches

	Equity Share	**Management Control**
Full ownership	100%	100%
Co-ownership	1-99% (based on ownership share)	If >50%: 100% If < 50%: 0
Majority owner and operational control of the facility	>50% based on ownership share	100%
Minority owner but operational control of the facility	<50% based on ownership share	0
Operator of the facility, but no ownership share	0	100%
Leasing	100%	100%
Joint Power Agreement	Varies with ownership share	If operational control or ownership >50%: 100% emissions If no operational control or ownership <50%: 0

Chapter 3: Defining Operational Boundaries

This chapter provides guidance on determining which direct and indirect GHG emissions you must report to the Registry. You must report all significant CA or U.S. direct emissions.

3.1 Direct Emissions

Within the power/utility sectors, direct emissions come from:

- Stationary combustion from the onsite production of heat, steam, or electricity owned or controlled by your organization.
- Fugitive leaks or venting from operations owned or controlled by your organization.
- Processes such as emission control technologies and other activities that are owned or controlled by your organization.
- Mobile combustion from non-fixed sources that are owned or controlled by your organization.

This protocol provides guidance for you to calculate and report direct emissions from:

1. Stationary Combustion;
2. Fugitive Emissions from Electricity Transmissions & Distribution; and
3. Process Emissions from SO_2 scrubbers.

Reporters should consult the General Reporting Protocol for guidance on calculating and reporting direct emissions from:

- **Mobile Combustion,**
- **Fugitive Emissions** from **Air Conditioning and Refrigeration Systems**, and
- **Fugitive Emissions** from **Fire Suppression Equipment.**

The Registry intends to revise this protocol to include guidance for calculating the fugitive and process emissions from natural gas transmission, storage & distribution.

3.2 Indirect Emissions

Indirect emissions occur because of your actions, but are produced by sources owned or controlled by another entity. Indirect emissions come from:

1. Electricity, steam, heating and cooling purchased and consumed: These include emissions from the generation of purchased energy that is consumed in equipment owned or controlled by your organization.

2. Transmission and distribution losses:

   a. the portion of electricity purchased by your organization that is consumed during its transmission and distribution to end-use customers through equipment and infrastructure that is owned or controlled by your organization (T&D loss), and

   b. the portion of wheeled electricity that is consumed by transmission and distribution equipment and infrastructure that is owned or controlled by your organization, and

c. the portion of electricity consumed during its transmission and distribution to direct access customers.

Reporters should consult the General Reporting Protocol for guidance on calculating and reporting **indirect emissions** from:

- **Electricity Use,**
- **Co-generation,**
- **Imported Steam**, and
- **District Heating** or **Cooling.**

Example 3-1. Defining Operational Boundaries: An Electric Utility Company

An electric utility company operating in California owns electric generating facilities, an electric transmission and distribution system, and a natural gas transmission and distribution system. The company generates electricity and also purchases it from other generators to supply customers in California. The company also has office buildings and a fleet of vehicles that it uses in its business operations.

This electric utility company's entity-wide GHG inventory will include the following direct and indirect emission sources:

- Stationary combustion
- Mobile combustion
- Process emissions
- Fugitive emissions
- Indirect emissions from energy imported and consumed at office buildings
- Indirect emissions from T&D losses

3.3 Establishing and Updating a Baseline

All Registry participants are encouraged to establish a baseline and adjust it over time when your organization undergoes structural changes. Chapter 3 of the GRP walks you through the options and process of selecting and establishing your baseline. For power/utility entities, the GRP provides all guidance needed to establish a baseline.

Chapter 4: Geographic Boundaries

This chapter discusses requirements for determining the geographic boundaries of your GHG Emission Report.

4.1 Determining Geographic Boundaries

You have the option of defining the reporting scope of your GHG inventory in two ways, either:

1) All GHG emissions in California (CA reporting), or
2) All GHG emissions in the US--separated into California and non-California inventories (U.S. reporting).

The Registry does not currently certify GHG emissions data from operations outside the U.S. However, you are encouraged to gather and retain this data for reporting to the Registry in subsequent years. You may currently report international emissions in the optional reporting section.

Emissions are calculated based on where you generate, transmit or distribute electricity. If you own electricity generation inside and outside of California, your total reported direct emissions may change, depending on whether you report your U.S. or your CA emissions.

4.2 U.S. Reporting

To determine your U.S. direct emissions, follow the steps in Chapters 5-7 to calculate your total emissions from stationary combustion, power/utility processes, and fugitive sources for all facilities located in the U.S. Follow the steps in the GRP to calculate your total direct emissions from mobile combustion.

To determine your U.S. indirect emissions, follow the steps in Chapters 8 to calculate your total indirect emissions associated with energy purchased and consumed within the United States.

4.3 Reporting California Emissions

To determine your California direct emissions, you must calculate the emissions associated with electricity generated at any stationary combustion plant you own that is located inside the borders of the state of California. For generation stations physically located in the state, this includes all of the direct emissions associated with these facilities. You do not need to report any emissions from your out-of-state plants as part of your California-only inventory. *Note: information on the emissions from fossil fuel combusted at all of your plants to generate electricity delivered to California customers is required to calculate the required efficiency metrics. For more information, see Chapter 9: Industry-Specific Efficiency Metrics.*

For transparency, you must also report the portion of your direct emissions associated with electricity from California plants delivered out of state.

To determine your California indirect emissions, you must calculate the emissions associated with energy purchased and consumed within the state of California. Emissions associated with electricity purchased and delivered to end-users in California should be included in the calculation of your California-only indirect emissions, regardless of where the power is generated.

Example 4-1 illustrates how your reported direct and indirect emissions may change, depending

on whether you choose to report your CA or your U.S. emissions.

Information on calculating direct emissions is provided in Chapter 5: Direct Emissions from Stationary Combustion.

Example 4-1. Determining Geographic Boundaries: An Electric Generation, Transmission and Distribution Company with facilities in California and Nevada

AB Power owns three electric generation facilities in California, two generating plants located in Nevada, and also has a transmission and distribution system through which it delivers electricity to customers in California.

The electricity that AB Power delivers to its customers comes from the company's own facilities located in California, its power plants located in Nevada, from power purchases from other generators located in Oregon, and from spot market purchases.

Reporting U.S. emissions:

When reporting all U.S. emissions, AB Power calculates all fugitive, process, mobile and stationary combustion emissions associated with its facilities in California and Nevada and reports these as direct emissions. All emissions associated with electricity purchased from Oregon generators and consumed by AB Power through T&D or other activities are reported as indirect emissions.

Reporting California emissions:

When reporting California emissions only, AB Power calculates all direct emissions, including fugitive, process, mobile and stationary combustion, of its facilities in California. AB Power does not report any emissions from its Nevada plants. All emissions associated with electricity purchased from Oregon generators and consumed by AB Power through T&D or other activities are reported as indirect emissions. All emissions associated with electricity purchased from the spot market and consumed by AB Power through T&D or other activities are also reported as indirect emissions.

4.4 Geographic Boundaries vs. Organizational Boundaries

Your geographic boundary is not the same as your organizational boundary. Organizational boundaries reflect financial, legal and operational relationships. Geographic boundaries reflect the physical location of your facilities. If you have facilities located both inside and outside of California, reporting according to geographic boundaries may not capture all of your organization's emissions. Thus, we *strongly* recommend that organizations with operations inside and outside of California report their U.S. emissions.

4.5 Level of Detail in Reporting

As stated in the General Reporting Protocol, you must report, at a minimum, your California direct and indirect emissions in the appropriate categories. All data is reported through CARROT. However, the Registry recommends that you report your GHG emissions information at a sub-entity (i.e., business unit or facility) level. Reporting to this level of detail in CARROT will help to insure accuracy of your calculations, provide transparency and standardization, and thus help to lower your total costs of certification.

Chapter 5: Direct Emissions from Stationary Combustion

What you will find in Chapter 5	This chapter provides guidance on quantifying direct emissions from stationary combustion in the power/utility sector, including electric power generation, steam generation, auxiliary equipment, flaring and other related activities involving the combustion of fossil fuels or biomass fuels.
Information you will need	You may need information on your reporting under 40 CFR Part 75, total annual fuel use broken down by fuel type, electricity production, steam production and monitoring equipment information.

Power/utility companies that own or operate large combustion facilities may burn any combination of the following fuels: coal, oil, natural gas, biomass or others for the production of electricity and/or heat and steam. Although hydrocarbon fuel combustion emits CO_2, CH_4, and N_2O, the CO_2 emissions associated with stationary combustion facilities will likely make up the largest percentage of your CA or U.S. greenhouse gas inventory.[4]

The amount of CO_2 emitted from hydrocarbon combustion predominantly depends on the quantity of the fuel and carbon content of fuel consumed. To a lesser extent, the oxidation fraction of a particular fuel, under standard operating conditions and practices, also influences CO_2 emissions. (An oxidation fraction reflects an incomplete combustion process, to the extent that all the carbon contained in the fuel does not oxidize into CO_2 but remains as ash or unburned carbon.)

Non-fossil carbon bearing fuels (e.g., landfill gas, wood and wood waste, etc.) may also be combusted in stationary sources in the power/utility sector. International consensus on the net impact on climate from the combustion of biofuels has not yet been reached. You should not report biogenic CO_2 emissions as GHG emissions. However, it is important to identify the contribution of these emissions as a part of your overall activities. Thus, you must identify and report biomass CO_2 emissions as "biogenic emissions," in a category separate from fossil fuel emissions. Note that CH_4 and N_2O emissions from the combustion of biomass are not considered biogenic and should be calculated and reported as part of your direct emissions inventory.

5.1 Stationary Combustion Equipment

The power/utility sectors use a number of stationary combustion technologies to generate, transmit, and distribute electricity and produce heat and/or steam. Power/utility companies also combust natural gas and other fossil fuels to transport, store, and distribute natural gas. Table 5.1 below lists examples of stationary combustion equipment that directly emit GHGs.

[4] This is because during the combustion process, nearly all the carbon contained in hydrocarbon fuels is converted to CO_2, regardless of the fuel type or combustion configuration.

Table 5.1 Stationary Combustion Equipment

Technology Category	Source Type
Boilers	Natural gas boilers, residual or distillate oil boilers, coal-fired boilers (pulverized coal, fluidized bed, spreader stoker, tangentially fired, wall fired, etc.), biomass fired boilers, dual -fuel-fired boilers, and auxiliary boilers
Turbines	Combined cycle gas, simple cycle gas, combined heat and power, microturbines, steam turbines, and integrated gasification combined cycle
Internal Combustion Engines	Emergency and backup generators, reciprocating engines, compressors, firewater pumps, and black start engines
Flares	Natural gas, landfill gas, and waste gas
Other	Fuel cells, geothermal, anaerobic digesters, and refuse-derived fuels

5.2 GHG Emissions Quantification Methods

To quantify CO_2 emissions from stationary combustion sources, power/utility companies must use one or both of the following two methods:

1. Measurement-based methodology

2. Fuel use calculation-based methodology

For most power/utility companies, the information needed to quantify and report direct stationary combustion GHG emissions to the Registry should be available or easily derived from existing reporting activities. For major stationary sources, most power/utility companies already account for and report air pollution emissions to local, state and/or federal regulatory agencies, as well as total annual fuel use, and electricity, steam and heat production. [5]

Most large electric generating units have continuous emissions monitoring systems (CEMs) that track their CO_2 emissions. Smaller units, however, have not installed these monitors, but rely on fuel use data to determine their emissions. Because of these varying requirements, you may have to use both the measurement-based and the calculation-based methodologies to report to the Registry.

To maintain consistency with other programs, entities that are required to report emissions to the U.S. EPA according to 40 CFR Part 75 and/or state or local environmental agencies are *strongly encouraged* to report the same CO_2 emissions information to the CA Registry.

Whichever method or combination of methods are used to calculate your GHG emissions inventory, you should use the same reporting methodology from year to year to maintain consistency and comparability between inventory years.

5.2.1 Measurement-Based Methodology

Continuous emissions monitoring systems (CEMS) are the primary emissions monitoring method used in the power/utility sector. The 40 CFR Part 75 rule includes requirements for installing, certifying, operating, and maintaining CEMS for measuring and reporting SO_2, NOx, CO_2, O_2, opacity, and volumetric flow.[6] The Part 75 rule also includes requirements for measuring and reporting emissions when CEMs are not utilized.

[5] 40 CFR Part 75 provides all the protocols and procedures for operating continuous emissions monitors and quantifying and reporting air pollution and CO_2 emissions to the U.S. EPA. U.S. EPA Clean Air Markets Division - Consolidated Part 72 and 75 Regulations http://www.epa.gov/airmarkets/monitoring/consolidated/index.html

[6] U.S. EPA, Clean Air Markets Division, *Part 75 CEMS Field Audit Manual*, July 16, 2003.

You may use either of the following two CEMS configurations to determine annual CO_2 emissions:

1. CO_2 CEMS and a Flow Monitoring System that measure CO_2 concentration, volumetric gas flow, and CO_2 mass emissions.

2. O_2 CEMS and a Flow Monitoring System that measure O_2 concentration, volumetric gas flow, and O_2 mass emissions to calculate CO_2 emissions.

As previously stated, if you are required to use CEMs under 40 CFR Part 75, you should also measure and report your CO_2 emissions to the Registry using this method. You must also specify which CEMS configuration you are using to monitor your CO_2 emissions. If you do report using CEMs, you must continue to use CEMs for those same facilities each year to ensure consistency over time.

As discussed above, the Registry requires that participants identify and report biomass CO_2 emissions as "biogenic emissions," separate from fossil fuel emissions. Thus, if you combust biomass fuels in any of your units using CEMS to report CO_2 emissions, you must calculate the emissions associated with the biomass fuels (Equation 5a) and subtract this from your total measured emissions (Equation 5b). You must report these separate from your fossil emissions, along with any other biogenic emissions.

Equation 5a	**Calculating Biomass Carbon Dioxide (CO_2) Emissions (Fuel Consumption is in MMBtu)**					
Total Emissions (metric tons)	=	Fuel Consumed (MMBtu)	**x**	Adjusted Emission Factor (kg CO_2/MMBtu)	**x**	0.001 metric tons/kg

Equation 5b	**Backing Out Biomass Carbon Dioxide (CO_2) Emissions from CEMS**			
Total Emissions (metric tons)	=	Total CEMS CO_2 Emissions (metric tons)	-	Total Biomass CO_2 Emissions (metric tons)

Example 5-2 illustrates a case where biomass is co-fired and emissions are monitored through a CEMS.

Example 5-2. Biomass Co-Firing in a Unit with CEMS

An electric utility company operating in California reports the CO_2 emissions from its major electric generating facilities using the CEMS already installed on those units. At one of its natural gas-fired units it co-fires with wood; the emissions associated with each combustion activity are mixed in the exhaust stack and measured collectively by the CEMS device. To report its CO_2 emissions from this unit, the utility must calculate the portion of CO_2 emissions from combusting wood, and subtract it from the total emission measurement. To do so, the company must quantify the amount of biomass consumed by the unit, and multiply that value by the wood-specific CO_2 emission factor. This value is then subtracted from the total CO_2 emissions measured by the CEMS. See Equations 5a and 5b below.

Equation 5a	Calculating Biomass Carbon Dioxide (CO_2) Emissions (Fuel Consumption is in MMBtu)							
Total Emissions (metric tons)	=	Fuel Consumed (MMBtu)	x	Adjusted Emission Factor (kg CO_2/MMBtu)	x	0.001 metric tons/kg		
Total Emissions (metric tons)	=	1,000,000 MMBtu	x	90.94 kg CO_2/MMBtu	x	0.001 metric tons/kg	=	90,940 metric tons CO_2

Equation 5b	Subtract Biomass Carbon Dioxide (CO_2) Emissions from CEMS					
Total Emissions (metric tons)	=	Total CEMS CO_2 Emissions (metric tons)	-	Total Biomass CO_2 Emissions (metric tons)		
Total Emissions (metric tons)	=	8,000,000 metric tons CO2	-	90,940 metric tons CO_2	=	7,909,060 metric tons CO_2

5.2.2 Fuel Use Calculation-Based Methodology

To calculate your GHG emissions based on fuel use, you must determine how much and what type of fuel was combusted, determine how much of the fuel is oxidized in the combustion process, and determine its CO_2 content.

To calculate CO_2, CH_4, and N_2O emissions from stationary combustion, you should:

1. Identify the annual consumption of each fossil and non-fossil fuel type combusted in your operations;
2. Apply a Heat Content factor to convert fuel use from physical units to energy units;
3. Calculate or select the appropriate emission factor for each fuel;
4. Calculate each fuel's CO_2 emissions and convert to metric tons;
5. Calculate each fuel's CH_4 and N_2O emissions, if any, and convert to metric tons; and
6. Convert CH_4 and N_2O emissions to CO_2 equivalents and sum all subtotals.

Each of these steps is explained in further detail below.

Step 1: Identify the annual consumption of each fossil and non-fossil fuel

First, determine your annual fuel use by fuel type, measured in terms of physical units (e.g., mass or volume). For stationary combustion sources, you may use one of two methods, listed below, from most accurate to least accurate. Note that while either one is acceptable for reporting to the Registry, as the methods decrease in accuracy, they also increase in the level of certification required.

Step 1a. Methods for Obtaining Fuel Use Data

Step 1a1. On-site measurements

Determine the amount of fuel combusted at each combustion unit by reading individual meters located at the fuel input point. Then, sum the fuel use for each unit to arrive at the facility-wide fuel use. If you have a facility-wide fuel totalizer, you can use the amount of fuel from the totalizer.

Step 1a2. Calculate annual mass balance
Using fuel purchase records and your fuel inventory log, calculate your total fuel usage. Convert fuel purchase and storage data to estimates of actual fuel use using Equation 5d:

Equation 5c	**Calculating Actual Annual Fuel Usage**							
Total Annual Fuel Burned	=	Annual Fuel Purchases	+	[Fuel Stock at Beginning of Year	-	Fuel Stock at End of Year	]

Step 2: Convert fossil fuel use from physical units to energy units

At this point, your total fuel use is expressed in physical units (mass or volume). Before you can apply a CO_2 emission factor, you must first convert the physical units to heat content (HC), expressed in million British Thermal Units (MMBTU).

You can use one of three methods to report heating values:

1. Direct measurement according to industry-approved methods;
2. Fuel supplier-provided; and
3. Approved default factors.

Default heat content values for each fuel type are provided in Table 5.2, below. You should calculate heat content based on higher heating values (HHV). (See GRP for discussion of converting HHV to LHV).

Step 3: Apply or Derive an Appropriate CO_2 Emission Factors for Each Fuel

After determining the amount of fuel combusted (expressed in energy content, MMBTU), you must next determine the amount of CO_2 emitted into the atmosphere per unit of fuel. To calculate this information you can use an emission factor obtained from an approved source, listed in Step 3a. To derive your emission factor based on your specific fuel purchases, you follow the guidance in Step 3b.

Step 3a: To identify your general emission factor, you can use any of the three following methods. These are listed beginning with the most accurate:

A. **Monitoring over a range of conditions and deriving emission factors.** Periodic source testing according to industry-approved methods.

B. **Equipment manufacturer data.** Emission performance guaranteed by manufacturer testing and certification.

C. **Default emission factors.** Fuel-specific CO_2 emission factors representing average fuel

and technology characteristics.

Table 5.1 Default CO_2 Emission Factors

Fossil Fuel	Emission Factor (kg CO_2/MMBtu)
Anthracite Coal	103.61
Bituminous Coal	93.50
Sub bituminous Coal	97.12
Lignite Coal	96.61
Coke	102.11
Natural Gas	53.05
Distillate Oil	73.14
Residual Oil	78.79
Kerosene	72.30
Petroleum Coke	102.11
LPG	62.99
Ethane	59.60
Propane	63.04
Isobutane	65.08
n-Butane	64.97
Geothermal[7]	n.a.
Wood – dry	90.94
Landfill gas	52.07
Waste water treatment biogas	52.07

See sources noted for Table 5.2.

Step 3b: To derive your emission factor, follow this three-step process:

1. **Determine the Carbon Content of the Fuel**. You can obtain this information either directly from your fuel supplier based on the actual content of the fuel you purchase, or you can use a default factor, provided in Table 5.2 below.

2. **Multiply by an Oxidation Fraction**. Inefficiencies in the combustion process prevent all the carbon in fossil fuels from oxidizing into CO_2. As a result, a small fraction of the carbon remains unburned as soot or ash, but this is different for each fuel. To identify how much of the carbon in your fuel is oxidized, multiply your purchases of each fuel by its respective oxidation factor, identified in Table 5.2.

3. **Convert to CO_2**. After determining the oxidized carbon content of a fuel, the last step is to convert from carbon emissions to carbon dioxide emissions. Multiply this amount by the molecular weight of CO_2 over carbon (44/12).

This process is outlined in Equation 5d below:

[7] A study of California's geothermal power plants found the state average CO_2 emission rate to be roughly 150 lb/MWh. The newest generation of flash steam geothermal plants emit CO_2 at roughly 100 lb/MWh. There are no CO_2 emissions from binary systems, because any CO_2 present in the geothermal resource (steam or water) is reinjected into the earth.

Equation 5d

$$\text{Emissions} = \sum_{i=1}^{n} \text{Fuel}_i \times \text{HC}_i \times [\text{CC}_i \times \text{OF}_i \times \frac{\text{CO}_{2(\text{m.w.})}}{\text{C}_{(\text{m.w.})}}]$$

Where:

Fuel_i	=	Mass or Volume of the Fuel Type *i* Combusted
HC_i	=	Heat Content of Fuel Type *i* (energy / mass or volume of fuel)
CCi	=	Carbon Content Coefficient of Fuel Type *i* (mass C / energy)
OF_i	=	Oxidation Fraction of Fuel Type *i*
$\text{CO}_{2(\text{m.w.})}$	=	Molecular weight of CO_2
$\text{C}_{(\text{m.w.})}$	=	Molecular weight of C

Table 5.2: Default Values for Heat Content, Carbon Content, and Fraction of Carbon Oxidized for Fuels used for Electric Power Generation

Fossil Fuel	Heat Content (HHV)	Carbon Content	Fraction Oxidized
Coal and Coke	**(MMBtu/Short Ton)**	**(kg C/MMBtu)**	
Anthracite Coal	25.09	28.26	0.990
Bituminous Coal	24.93	25.50	0.990
Sub bituminous Coal	17.25	26.49	0.990
Lignite Coal	14.21	26.35	0.990
Coke	24.80	27.85	0.990
Natural Gas	**(Btu/standard Ft^3)**	**(kg C/MMBtu)**	
Natural Gas	1,027.00	14.47	0.995
Petroleum	**(MMBtu/Barrel)**	**(kg C/MMBtu)**	
Distillate Oil	5.825	19.95	0.990
Residual Oil	6.287	21.49	0.990
Kerosene	5.670	19.72	0.990
Petroleum Coke	6.024	27.85	0.990
LPG	3.788	17.18	0.995
Ethane	2.916	16.25	0.995
Propane	3.824	17.20	0.995
Isobutane	4.162	17.75	0.995
n-Butane	4.328	17.72	0.995
Non-Fossil Fuel			
Solid	**(MMBtu/Short Ton)**	**(kg C/MMBtu)**	
Wood – dry	17.200	25.05	0.900
Gas	**(Btu/standard Ft^3)**	**(kg C/MMBtu)**	
Landfill gas	502.500	14.20	0.995
Waste water treatment biogas	Varies (obtain from operator)	14.20	0.995

Sources:

Coal - Heat Contents and Carbon Content Coefficients based on the approach outlined in the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 - 2001,* EPA430-R-03-004, U.S. Environmental Protection Agency, Washington, DC, April 2003. The approach uses coal physical characteristics from the *CoalQual Database Version 2.0,* U.S. Geological Survey, 1998, and coal production data from the *Coal Industrial Annual,* U.S. Department of Energy, Energy Information Administration, Washington, DC, 2002 (year 2000 data used). Fractions Oxidized from Appendix A (Table A-15) of EPA inventory report.

Coke - Heat Content from the *Annual Energy Review 2002,* DOE EIA 0384(2002), U.S. Department of Energy, Energy Information Administration, Washington, DC, October 2003.

Carbon Content Coefficient and Fraction Oxidized from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 - 2001,* EPA430-R- 03-004, U.S. Environmental Protection Agency, Washington, DC, April 2003. Values for coke are based on petroleum coke.

Natural Gas and Petroleum (except LPG) - Heat Contents from the *Annual Energy Review 2002,* DOE EIA 0384(2002), U.S. Department of Energy, Energy Information Administration, Washington, DC, October 2003. Carbon Content Coefficients and Fractions Oxidized from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 - 2001,* EPA430-R-03-004, U.S. Environmental Protection Agency, Washington, DC, April 2003.

LPG - Heat Contents and Carbon Content Coefficients for LPG components from Appendix B (Table B-9) of *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 - 2001,* EPA430-R-03-004, U.S. Environmental Protection Agency, Washington, DC, April 2003. Heat Content and Carbon Content Coefficient values for LPG based on values of components and assumed percent by volume of 6.5% ethane, 88% propane, 2.3% isobutane, and 3.0% n-butane. Fractions Oxidized from Appendix A (Table A-15) of EPA inventory report, Fractions Oxidized for LPG components assumed to be the same as for LPG

Wood - Heat Content and Fraction Oxidized from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 - 2001,* EPA430-R-03- 004, U.S. Environmental Protection Agency, Washington, DC April 2003, Chapter 2 text describing the methodology used to calculate emissions from Wood Biomass and Ethanol Consumption. Carbon Content Coefficient calculated based on heat content and assumed 47.5% carbon in dry biomass also from the EPA inventory report (Chapter 2 text lists a range of 45% - 50%). The factors presented in Table B- 2 represent emissions from wood combustion only and do not include any emissions or sinks from wood growth or harvesting.

Gas - Heat Content for landfill gas based on *Emissions and Sinks: 1990 - 2001,* EPA430-R-03- 004, U.S. Environmental Protection Agency, Washington, DC April 2003 and assumed landfill gas composition of 50% CH4 and 50% CO_2 by volume. Heat Content for wastewater treatment gas could be calculated based on methane heat content and percent methane in the gas. Carbon Content Coefficients are the carbon content coefficient of methane from the EPA inventory report. Fraction Oxidized also from the EPA inventory report, assumed to be the same as natural gas.

Step 4: Apply CH_4 and N_2O emission factors for each fuel

During the hydrocarbon combustion process, N_2O formation follows complex pathways and depends on a variety of factors, including fuel type and combustion technology and configuration. CH_4 formation is usually dependent on conditions similar to those that create N_2O. Therefore, the following emission factors for CH_4 and N_2O are broken down by fuel type, combustion technology, and equipment configuration. This contrasts with CO_2 emission factors, which are almost exclusively dependent on fuel type.

Table 5.3 Default CH_4 and N_2O Factors

Fossil Fuel	Combustion Technology	Equipment Configuration	CH_4 (kg CH_4/MMBtu)	N_2O (kg N_2O/MMBtu)
Coal	**Pulverized Bituminous**	**Dry Bottom, wall fired**	0.000699	0.000522
		Dry Bottom, tangentially fired	0.000699	0.001397
		Wet Bottom	0.000871	0.001397
	Bituminous Spreader Stokers	**With and Without Reinjection**	0.001048	0.000699
	Bituminous Fluidized Bed	**Circulating Bed**	0.001048	0.061063
		Bubbling Bed	0.001048	0.061063
	Bituminous Cyclone Furnace		0.000172	0.001569
	Lignite Atmospheric Fluidized Bed		NA	0.070874
Oil	**Residual Fuel Oil/Shale Oil**	**Normal Firing**	0.000848	0.000331
		Tangential Firing	0.000848	0.000331
	Distillate Fuel Oil	**Normal Firing**	0.000907	0.000358
		Tangential Firing	0.000907	0.000358
	Large Diesel Fuel Engines >447 kW		0.003674	NA
Natural Gas	**Boilers**		0.001021	0.000980
	Large Gas Fired Turbines >3 MW		0.003901	0.001361
	Large Dual Fired Engines		0.272155	NA

Source: U.S. EPA's Compilation of Air Pollutant Emission Factors, Vol. 1: Stationary Point and Area Sources. Converted from pounds to kilograms using the conversion factor of 0.453592.

Step 5. Calculate each fuel's CO_2 emissions and convert to metric tons

If your fuel consumption is expressed in MMBtu, use Equation 5e. If your fuel is expressed in mass units (i.e., gallons, short tons, cubic feet, etc.) use Equation 5f.

Equation 5e	**Total CO_2 Emissions (Fuel Consumption is in MMBtu)**					
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CO_2/MMBtu)	**x**	Fuel Consumed (MMBtu)	**x**	0.001 metric tons/kg

Equation 5f	Total CO_2 Emissions (Fuel Consumption is in Mass Units)					
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CO_2/mass unit)	x	Fuel Consumed (mass unit)	x	0.001 metric tons/kg

Step 6. Calculate each fuel's CH_4 and N_2O emissions, if any, and convert to metric tons
If your fuel consumption is expressed in MMBtu, calculate CH_4 emissions using Equation 5g and N_2O emissions using Equation 5h. If fuel consumption is expressed in mass units, use Equation 5i and 5j.

Note: if non-CO_2 gases are *de minimis* after they are converted to CO_2e and metric tons, you may choose to not report them to the Registry. Also, you are encouraged, but not *required* to report non-CO_2 emissions until your fourth calendar year of reporting to the Registry.

Equation 5g	Total CH_4 (Fuel Consumption is in MMBtu)					
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CH_4/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg

Equation 5h	Total N_2O Emissions (Fuel Consumption is in MMBtu)					
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg N_2O/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg

Equation 5i	Total CH_4 Emissions (Fuel Consumption is in Mass Units)					
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CH_4/Mass Units)	x	Fuel Consumed (Mass Units)	x	0.001 metric tons/kg

Equation 5j	Total N_2O Emissions (Fuel Consumption is in Mass Units)					
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg N_2O/Mass Units)	x	Fuel Consumed (Mass Units)	x	0.001 metric tons/kg

Step 7. Convert CH_4 and N_2O emissions to CO_2 equivalents and sum all subtotals
To incorporate and evaluate non-CO_2 gases in your GHG emissions inventory, you must convert the mass estimates of these gases to CO_2 equivalent. To do this, multiply the emissions in units of mass by global warming potential (GWP). Table 5.4 below lists the 100-year GWPs to be used to express emissions on a CO_2 equivalent basis.

Equation 5k	Converting Mass Estimates to Carbon Dioxide Equivalent			
Metric Tons of CO_2e	=	Metric Tons of GHG	x	GWP

Table 5.4 Comparison of GWPs from the IPCC's Second and Third Assessment Reports

Greenhouse Gas	GWP (SAR, 1996)	GWP (TAR, 2001)
CO_2	**1**	1
CH_4	**21**	23
N_2O	**310**	296
HFC-123	**11,700**	12,000
HFC-125	**2,800**	3,400
HFC-134a	**1,300**	1,300
HFC-143a	**3,800**	4,300
HFC-152a	**140**	120
HFC-227ea	**2,900**	3,500
HFC-236fa	**6,300**	9,400
HFC-43-10mee	**1,300**	1,500
CF_4	**6,500**	5,700
C_2F_6	**9,200**	11,900
C_3F_8	**7,000**	8,600
C_4F_{10}	**7,000**	8,600
C_5F_{12}	**7,500**	8,900
C_6F_{14}	**7,400**	9,000
SF_6	**23,900**	22,000

Source: Intergovernmental Panel on Climate Change, Second Assessment Report (1996) and Third Assessment Report (2001).

5.2.3 Biogenic Emissions

As stated above, the Registry distinguishes between fossil fuel emissions (anthropogenic emissions) and non-fossil fuel emissions (biogenic emissions). In reporting your GHG emissions inventory, you should include all of your anthropogenic emissions in your report. Consistent with international practice at this time, you are also required to document your biogenic emissions used for stationary combustion, but you should report them separately from your direct emissions from stationary combustion. The same step-by-step procedure to determine GHG emissions from fossil fuels applies to non-fossil fuels.

For municipal solid waste-to-energy facilities (MSW), you must calculate your CO_2 emissions resulting from the incineration of waste of fossil fuel origin (e.g. plastics, certain textiles, rubber, liquid solvents, and waste oil) and include it in your GHG emissions inventory. However, your CO_2 emissions from combusting the biomass portion of MSW (e.g., yard waste, paper products, etc.) should be recorded as "biogenic emissions." Information on the biomass portion of MSW will be site-specific and should be obtained from a local waste characterization study.

5.2.4 Calculating Stationary Combustion for California Reporting

If you are reporting only your California emissions and you **generate and deliver** electricity to

customers in California, you will calculate your stationary combustion emissions according to the guidance in this chapter for all electricity generation from stations located in California.

For California reporting, you should report all of the emissions associated with plants physically located in the state.

Note: To calculate your required efficiency metrics, for each plant that you own outside of California but that provides power to your customers in California, you will need to know the emissions from fuel combustion associated with the portion of electricity you generate that is delivered to California. This is true regardless of the physical location of the plant.

If you share ownership of the plant, you should only report the portion of emissions for which you are responsible, and the portion of emissions delivered to California. If you are reporting by equity share, this will correspond to your ownership share (Note: equity share is the preferred method of reporting for the power/utility sectors). For instance, if you have 50% ownership of a plant that delivers 80% of its output to California customers, you would report half of the emissions associated with 80% of the plant's output. If you are reporting using management control, you will report either 100% or none of the emissions associated with the output delivered to California.

Because the resources of the electricity deliveries are known, you should use the GHG emission factor associated with that purchase.

Example 5-1: Calculating Direct Emissions from Stationary Combustion

AB Power Corporation

AB Power is an electric utility operating in California. It has two 800 MW generating units, one in California that burns natural gas and one at a mine mouth in Wyoming that combusts bituminous coal in dry bottom, wall-fired boilers. All of the generation from its California unit serves its California customers; 80% of the power generated at its Wyoming unit serves California customers. AB Power also owns a natural gas pipeline system in California, which includes natural gas compressor stations that combust natural gas.

Step 1: Identify all types of fuel directly combusted.

Table 5-6. Fuel Type, Sector, and Location

Fuel	Sector	Location
Natural Gas	Electric Power Generation	California
Natural Gas	Natural Gas System	California
Coal	Electric Power Generation	Wyoming

Step 2: Determine annual consumption of each fuel.

AB Power directly measures the energy content (MMBTU) of the fuel used in both of its power plants and its natural gas compressor stations. From fuel purchase records, AB Power determined that last year it consumed 10,000,000 MMBtu of natural gas and 22,000,000 MMBtu of coal for power generation. It also consumed 1,000,000 MMBtu of natural gas in its compressor stations.

Step 3: Select the appropriate emission factors for each fuel from Tables 5.2 and 5.3.

Step 4: Calculate each fuel's carbon dioxide emissions

Equation 5i	**Carbon Dioxide (CO_2) Emissions from Natural Gas**						
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CO_2/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg	
Total Emissions (metric tons)	=	53.05 kg CO_2/MMBtu	x	10,000,000 MMBtu	x	0.001 metric tons/kg	= 530,500 metric tons CO_2

Equation 5j	**Carbon Dioxide (CO_2) Emissions from Coal**						
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CO_2/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg	
Total Emissions (metric tons)	=	93.5 kg CO_2/MMBtu	x	22,000,000 MMBtu	x	0.001 metric tons/kg	= 2,057,000 metric tons CO_2

Equation 5k	**Total CO_2 Emissions from Natural Gas**						
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CO_2/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg	
Total Emissions (metric tons)	=	53.05 kg CO_2/MMBtu	x	1,000,000 MMBtu	x	0.001 metric tons/kg	= 53,050 metric tons CO_2

Total CO_2 from All Sources	=	**2,640,550 metric tons CO_2**

Step 5: Calculate each fuel's methane and nitrous oxide emissions.

Equation 5l	**Methane (CH_4) Emissions from Natural Gas**						
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CH_4/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg	
Total Emissions (metric tons)	=	0.001021kg CH_4/MMBtu	x	10,000,000 MMBtu	x	0.001 metric tons/kg	= 10.21 metric tons CH_4

Equation 5m	**Methane (CH_4) Emissions from Coal**							
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CH_4/MMBtu)	x	Fuel Consumed (MMBtu)	X	0.001 metric tons/kg		
Total Emissions (metric tons)	=	0.000699 kg CH_4/MMBtu	x	22,000,000 MMBtu	X	0.001 metric tons/kg	=	15.37 metric tons CH_4

Equation 5n	**Methane (CH_4) Emissions from Natural Gas**							
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CH_4/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg		
Total Emissions (metric tons)	=	0.001021kg CH_4/MMBtu	x	1,000,000 MMBtu	x	0.001 metric tons/kg	=	1.02 metric tons CH_4

Total CH_4 from All Sources	=	**26.60 metric tons CH_4**

Equation 5o	**Nitrous Oxide (N_2O) Emissions from Natural Gas**							
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg N_2O/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg		
Total Emissions (metric tons)	=	0.000980 kg N_2O/MMBtu	x	10,000,000 MMBtu	x	0.001 metric tons/kg	=	9.8 metric tons N_2O

Equation 5p	**Nitrous Oxide (N_2O) Emissions from Coal**							
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg N_2O/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg		
Total Emissions (metric tons)	=	0.000522 kg N_2O/MMBtu	x	22,000,000 MMBtu	x	0.001 metric tons/kg	=	11.48 metric tons N_2O

Equation 5q	**Nitrous Oxide (N_2O) Emissions from Natural Gas**							
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg N_2O/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg		
Total Emissions (metric tons)	=	0.000980 kg N_2O/MMBtu	x	1,000,000 MMBtu	x	0.001 metric tons/kg	=	0.98 metric tons N_2O

Total CH_4 from All Sources	=	**22.26 metric tons N_2O**

In this case, it is likely that both methane and nitrous oxide emissions from stationary combustion are *de minimis*. See Chapter 10: Calculating De Minimis Emissions for more information on *de minimis* emissions.

Step 6: Convert CH_4 and N_2O Emissions to CO_2e and sum the subtotals.

Equation 5r	Converting Mass Estimates to Carbon Dioxide Equivalent					
Metric Tons of CO_2e	=	Metric Tons of GHG	x	GWP		
Metric Tons of CO2					=	2,640,550 metric tons CO_2
CH_4 Tons of CO_2e	=	metric tons CH_4	x	21	=	558.79 tons CO_2e
N_2O Tons of CO_2e	=	metric tons N_2O	x	310	=	6,901.84 metric tons CO_2e
				Total	=	**2,648,010.63 metric tons CO_2e**

Step 7: If California-only reporting, report only the emissions associated with facilities in California.

Equation 5r	Calculating Out of State Generation Delivered to California					
Metric Tons of CO_2e	=	Metric Tons of GHG	x	GWP		
Metric Tons of CO_2					=	530,500 metric tons CO_2
CH_4 Tons of CO_2e	=	10.21 metric tons CH_4	x	21	=	214 tons CO_2e
N_2O Tons of CO_2e	=	9.8 metric tons N_2O	x	310	=	3,038 metric tons CO_2e
				Total	=	**533,752 metric tons CO_2e**

Chapter 6: Direct Emissions from Processes

What you will find in Chapter 6:	This chapter provides guidance on quantifying direct emissions from power generation processes, including controlling emissions from power generation facilities.
Information you will need:	You may need information on your SO_2 and NO_x emission control technology systems installed on your electric generating units, specifications of certain electric generation facilities as appropriate, and the quantity of calcium carbonate utilized.

This protocol does not currently include guidance for calculating and reporting the methane (CH_4) and carbon dioxide (CO_2) emissions from natural gas transmission, storage and distribution systems which may represent a significant portion of a utility's process emissions. However, the Registry intends to revise this document in the near future to include such guidance.

In addition to stationary combustion emissions, you must account for any process-related GHG emissions that you have. These include:

- Sulfur dioxide (SO_2) scrubber emission control technology installed on many coal- and oil-fired electric generating units;
- NO_x emission control technologies such as selective catalytic reduction (SCR) and selective non catalytic reduction (SNCR) technologies;
- Coal gasification at clean coal facilities, e.g., integrated gasification combined cycle (IGCC); and
- Hydrogen production.

The Workgroup was unable to identify standardized methods to quantify process-related GHG emissions for hydrogen production, SCR, SNCR, and IGCC technologies.

6.1 SO_2 Scrubbers

Any wet flue gas desulfurization systems, fluidized bed boilers, or other emission controls with sorbent injection likely emit CO_2 during the SO_2 scrubbing process, from the use of calcium carbonate.

If you use CEMs to collect and report emissions data to the Registry for stationary combustion units that have SO_2 scrubbers installed, then the CEMs also capture the CO_2 emissions from the scrubbing.

If you are not reporting using CEMs and you have SO_2 scrubbers on your combustion units, you must follow the guidance in this chapter to quantify your process CO_2 emissions associated with SO_2 scrubbing.[8]

To calculate these process emissions follow the steps outlined below:

[8] This methodology can be found in the U.S. EPA's CEMs guidelines and procedures. For more information on EPA's CEMS guidelines and procedures, reference (40 CFR Part 75).

Step 1: Determine the Total Quantity of Sorbent Used
Using your company's purchase records, determine the total quantity of sorbent (tons of calcium carbonate ($CaCO_3$) used each year. Identify your total sorbent inventory at the beginning of year, your total sorbent purchases during the year, and your total sorbent inventory at year end

Use these values in Equation 6a:

Equation 6a	Annual Quantity of Sorbent Used						
Total Sorbent Used	=	[Total inventory at beginning of year	-	Total inventory at end of year]	+	Total purchases/ acquisitions	

Step 2: Calculate the Ratio of the Molecular Weight of CO_2 to the Sorbent
Divide the molecular weight of carbon dioxide (44) by the molecular weight of the calcium carbonate (100) and multiply by the calcium to sulfur stoichiometric ratio (1.00).

Equation 6b	Ratio of the Molecular Weight of $CO_2/CaCO_3$					
Ratio of the Molecular Weight $CO_2/CaCO_3$	=	Molecular Weight of CO_2 (44)	/	Molecular Weight of $CaCO_3$ (100)	x	Calcium to Sulfur Stoichiometric Ratio (1.00)

Step 3: Determine CO_2 Emissions and Convert to Metric Tons
Multiply the value obtained in Step 2 above by the total tons of $CaCO_3$ used to determine CO_2 emissions. Multiply by 0.907 to convert to metric tons. See Equation 6c below.

Equation 6c	Total Process Emissions (Metric Tons)					
Total Process CO_2 Emissions (metric tons)	=	[Calcium Carbonate Used (Tons)	x	Ratio of the Molecular] Weight of $CO_2/CaCO_3$	x	0.907 metric tons/short ton

Example 6-1: Calculating Process Emissions from SO_2 Scrubber Sorbent

AB Power owns an 800 MW coal-fired electric generating facility in Wyoming. To comply with the federal Acid Rain Program, it installed SO_2 scrubbers that use calcium carbonate as the sorbent for the scrubbers.

AB Power reports all of its CO_2 emissions to the Registry from this facility. To calculate its stationary combustion, it uses the fuel-based calculation method. Thus, it must also complete the following calculations to calculate the CO_2 emissions associated with operating its scrubbers, and report these as process emissions.

Step 1: Determine the Total Quantity of Sorbent Used
Based on company purchase records, AB Power determined that it used 10,000 tons of calcium carbonate at its Wyoming coal facility in its scrubber technology.

Table 6-1. Calcium Carbonate Use and Location	
Location	**Quantity of Calcium Carbonate Used (Tons)**
Wyoming	10,000

Step 2: Multiply the Total Quantity of Sorbent by the Ratio of the Molecular Weight of CO_2 to the Sorbent

Equation 6a	**Annual Quantity of Sorbent Used**						
Total Sorbent Used	=	[Total inventory at beginning of year	-	Total inventory at end of year]	+	Total purchases/ acquisitions	
10,000 tons	=	[9000 (tons)	-	9000 (tons)]	+	10,000 (tons)	

Equation 6b	**Ratio of the Molecular Weight of $CO_2/CaCO_3$**						
Ratio of the Molecular Weight $CO_2/CaCO_3$	=	Molecular Weight of CO_2 (44)	/	Molecular Weight of $CaCO_3$ (100)	x	Calcium to Sulfur Stoichiometric Ratio (1.00)	
Ratio of the Molecular Weight $CO_2/CaCO_3$	=	44	/	100	x	1.00	= 0.44

Step 3: Determine CO_2 Emissions and Convert to Metric Tons

Equation 6c	**Total Process Emissions (Metric Tons)**									
Total Process CO_2 Emissions (metric tons)	=	Calcium Carbonate Used (Tons)	x	Calcium to Sulfur Stoichiometric Ratio (1.00)	x	Molecular Weight of CO_2 (44)/Molecular Weight of $CaCO_3$ (100)	x	0.907 metric tons/short ton		
Total Process CO_2 Emissions (metric tons)	=	10,000 tons	x	1.00	x	0.44	X	0.907	=	3,991 metric tons CO_2

Chapter 7: Direct Fugitive Emissions

What you will find in Chapter 7	This chapter provides guidance on quantifying fugitive emissions from electric power transmission and distribution, and solid fuel storage and handling.
Information you will need	You may need information on your total annual purchases of SF_6, and solid fuel.

This protocol does not currently include guidance for calculating and reporting the methane (CH_4) and carbon dioxide (CO_2) emissions from natural gas transmission, storage and distribution systems which may represent a significant portion of a utility's fugitive emissions. However, the Registry intends to revise this document in the near future to include such guidance.

Fugitive emissions are unintentional releases of GHGs, for instance from joints, seals, and gaskets. Fugitive emissions from the power/utility sector include:

1. Sulfur hexafluoride (SF_6) from electricity transmission and distribution systems;
2. CH_4 from fuel handling and storage;
3. Hydrofluorocarbons (HFCs) from air conditioning and refrigeration systems (both stationary and mobile); and
4. Perfluorocarbons (PFCs) and HFCs from fire suppression equipment.

These sources are listed by segment, facility and equipment in Table 7.1 below.

This chapter provides guidance on quantifying fugitive emissions from:
- Electricity transmission and distribution systems, and
- Fuel handling and storage.

Reporters should consult the General Reporting Protocol for guidance on calculating and reporting direct fugitive emissions from:

- **air conditioning and refrigeration systems** (both stationary and mobile)
- **fire suppression equipment**.

Note: For most power/utility companies, CH_4 emissions from fuel handling and storage and emissions of PFCs/HFCs may be de minimis. For information on estimating the impact of these emissions, see Chapter 10: Calculating De Minimis Emissions.

Table 7.1 Fugitive Emission Sources within Power/Utility Sectors

Fugitive SF_6 Sources			
Segment	**Equipment**		
Electricity Transmission	Circuit Breakers, Current-Interruption Equipment, Transmission Lines, Transformers, Substations		
Electricity Distribution	Circuit Breakers, Current-Interruption Equipment, Distribution Lines, Transformers, Substations		
Other Fugitive Emission Sources			
Segment	**Facilities**	**Source**	**Emissions**
Solid Fuel Handling and Storage	Electric Generation Facilities, Fuel Storage Facilities	Coal Piles, Biomass Piles	CH_4
Stationary and Mobile Cooling and Refrigeration	Electric Generation Facilities, Office Buildings, Mobile Sources	Air Conditioning and Refrigeration Systems	HFCs
Fire Extinguishers	Electric Generation Facilities	Total Flooding Fire Extinguishing Systems	PFCs and HFCs

7.1 Fugitive Emissions from Electricity Transmission and Distribution

Within the electric power industry, SF_6 is a gas often used for electrical insulation, arc quenching and current interruption equipment used to transmit and distribute electricity. SF_6 is extremely stable and long lasting, and is also a potent greenhouse gas. It is estimated that the electric power industry uses about 80% of the SF_6 produced worldwide, with circuit breaker applications accounting for most of this amount.[9]

Fugitive SF_6 emissions from the electric utility industry are the result of normal operations and routine maintenance, as well as the use of older equipment. SF_6 can escape to the atmosphere during normal operations, releases from properly functioning equipment (due to both static and dynamic operation) and old and/or deteriorated gaskets or seals. SF_6 can also escape when gas is either transferred into or extracted from equipment for disposal, recycling, or storage.

7.2 Fugitive Emissions from Solid Fuel Handling and Storage

Fugitive emissions from solid fuel handling and storage are the result of

- CH_4 desorption from coal handling and storage;
- CH_4 and N_2O from decomposing
- Other causes.

Fugitive emissions from fuel handling and storage will likely be de minimis for power/utility entities. For help in determining whether your fugitive CH_4 emissions from fuel handling and storage are *de minimis*, see Chapter 10: Calculating De Minimis Emissions.

7.2.1 Coal Handling & Storage

In the course of mining, transporting and storing coal used for power generation, methane is emitted from underground mining, surface mining, and post-mining activities. Some methane

[9] Other uses of SF_6 include: semiconductor processing, blanket gas for magnesium casting, reactive gas in aluminum recycling to reduce porosity, thermal and sound insulation, airplane tires, spare tires, “air sole” shoes, scuba diving voice communication, leak checking, atmospheric tracer gas studies, ball inflation, torpedo propeller quieting, wind supersonic channels, and high voltage insulation for many other purposes, such as AWACS radar domes and X-ray machines.

remains in the coal after it is removed from the mine and can be emitted as the coal is transported, processed, and stored. Depending on the characteristics of the coal and the way it is handled after leaving the mine, the amount of methane released during post-mining activities can be significant and can continue for weeks or months. The greatest releases occur when coal is crushed, sized, and dried in preparation for industrial or utility uses.[10] The actual amount of gas that escapes into the atmosphere will be a function of the rate of methane desorption, the coal's original gas content, and the amount of time elapsed before coal combustion occurs.

7.2.2 Biomass Handling & Storage

In the handling and storage of biomass, methane is formed where anaerobic digestion occurs. Whether or not anaerobic conditions occur in the pile largely depends on the characteristics of the pile and its surroundings (height, surface, temperature) and the content of the biomass itself (particle size, density, moisture content). Biomass piles may also be a source of nitrous oxide emissions during the first stage of decomposition. [11]

7.3 Quantifying Fugitive SF_6 Emissions from Electricity Transmission and Distribution

To calculate your fugitive SF_6 emissions from electricity transmission and distribution operations, you should use the Mass Balance Approach, as outlined in the U.S. EPA SF_6 Emission Reduction Partnership for Electric Power Systems. The complete methodology is provided in Annex A to this protocol. An overview of the process is provided below.

7.3.1 Mass Balance Approach

This method uses a mass balance approach to calculate total fugitive SF_6 emissions.

Calculate your fugitive SF_6 emissions using the following seven-step process:

1. Determine Change in SF_6 Inventory.
2. Determine Purchases/Acquisitions of SF_6.
3. Determine Sales/Disbursements of SF_6.
4. Determine the Net Increase in the Total Nameplate Capacity of the Equipment.
5. Determine Total Annual Emissions (1+2-3-4).
6. Convert SF_6 Emissions to CO_2 equivalents.
7. Determine Emission Rate (optional).

[10] U.S. EPA, 1990.

[11] Consistent with international practice, CO_2 emissions from the combustion of biomass fuels used in electricity generation must be quantified and reported as biogenic emissions, but are not included in your total GHG emissions inventory, which tracks anthropogenic emissions. For more information on calculating these emissions, see *Chapter 5: Direct Emissions from Stationary Combustion*.

Chapter 8: Indirect Emissions from Energy Purchased and Consumed

What you will find in Chapter 8	This chapter provides guidance on quantifying indirect emissions from electricity purchased and consumed by companies in the power/utility sector. Indirect emissions are those that are a consequence of the actions of a reporting entity, but are produced by sources owned or controlled by another entity.
Information you will need	You may need information on your total annual purchases and deliveries of electricity.

This chapter provides guidance for you to quantify the indirect emissions associated with the portion of your purchased and wheeled electricity resold to your end-users that is consumed by your transmission and/or distribution system through line losses.

8.1 T&D Line Loss Sources in the Power/Utility Sectors

If you own transmission and/or distribution assets, you are responsible to report the electricity losses that occur in those systems. Since these losses are classified as "consumption" of the electricity, they are categorized as indirect emissions. Sources of transmission and distribution line losses include those areas and sources listed in Table 8.1 below.

Table 8.1: Transmission and Distribution Line Loss Sources

Segment	Facilities	Equipment
Electricity Transmission	Feeders and Transmission Lines	Transformers/Wires, Conductors
Electricity Distribution	Distribution Systems and Substations	Transformers/Wires

You must report the following indirect emissions:

1. *Indirect Emissions Associated with Transmission and/or Distribution Losses.* These are the emissions associated with 1) the portion of the electricity purchased for resale to end-users that is consumed by your T&D system, and 2) the portion of wheeled electricity that is consumed by your T&D system.[12]

2. *Purchased electricity, steam or heat for own consumption.* These are the emissions associated with the generation of purchased electricity, steam/heating/cooling that is consumed in equipment or operations owned or controlled by your organization (e.g., office buildings).

> Reporters should consult the General Reporting Protocol for guidance on calculating and reporting indirect emissions from:
>
> - electricity, steam or heat purchased for your own consumption.

If you are reporting only California emissions, you should follow the steps in this chapter to calculate the emissions associated with T&D Losses serving customers in California only and

[12] Wheeled electricity includes direct access (customer choice programs) where the T&D utility only transmits and/or distributes the power.

energy purchased and consumed at facilities in California only.

8.2 Quantifying Indirect Emissions Associated with Transmission & Distribution Losses

This section provides a default method for quantifying indirect GHG emissions associated with your consumption of purchased and wheeled electricity on your T&D system (T&D losses).

If you own and/or operate a transmission and/or distribution system, you must report the portion of indirect emissions associated with the amount of purchased and wheeled electricity that corresponds to your entity-wide T&D losses.

Please note: you do not need to account for the T&D losses associated with electricity that you generate and sell to end-users. These emissions are already reported in your inventory as direct stationary combustion emissions.

However, if you *purchase* electricity and *resell* it to end-users, you must report the indirect emissions associated with transmission and/or distribution of this electricity. You should also separately report the indirect emissions associated with transmission and distribution of wheeled electricity (including direct access).

8.2.1 Sources of Information on T&D Losses

Your organization may already track the data necessary to report using this methodology for state, federal or independent system operator (ISO) reporting purposes. For example, your organization may be required to report to the Federal Energy Regulatory Commission (FERC) under *FERC FORM 1 - Annual Report of Major Electric Utility*, to the U.S. Energy Information Administration (EIA) under *The Annual Electric Power Industry Report, Form EIA-861* or Public Electric Utility Database Form EIA-412**.**

> If you currently report FERC FORM 1, all information required to use this methodology is contained on:
>
> Page 401: *Electrical Energy Account*.
> Page 327: *Purchased Power,* and
> Page 328 *Transmission of Electricity for Others*.

8.2.2 Calculate T&D Losses

Calculate your **transmission and/or distribution losses** using the following fourteen steps:

1. Identify the Total Net Generation.

2. Identify the Total Purchases from Electricity Suppliers.

3. Identify Exchanges (Net).

4. Identify Wheeled (Net).

5. Identify Transmission by Others (Losses).

6. Identify Total Sources.

7. Identify Retail Sales to Ultimate Customers.

8. Identify Sales for Resale.

9. Identify Energy Furnished Without Charge.

10. Identify Energy Consumed by Respondent Without Charge.

11. Identify Energy Consumed by Facility (Independent Power Producers or Qualifying Facility).

12. Identify Total Energy Losses.

13. Identify T&D Loss Factor.

14. Identify Portion of Losses Attributable to Purchases and Wheeled Power.

Each of these fourteen steps to calculate your transmission and/or distribution losses is described in greater detail below.

Step 1: Identify Your Total Net Generation
Determine your net generation (gross generation minus plant use) in megawatt hours (MWh).

Step 2: Identify the Total Purchases from Electricity Suppliers
Add your total purchases (MWh) from all electricity suppliers including: nonutility power producers and power marketers, municipal departments and power agencies, cooperatives, investor-owned utilities, political subdivisions, state agencies and power pools, and marketing agencies.

Step 3: Identify Exchanges (Net)
Determine the net amount of energy exchanged in MWh. Calculate the difference between the amount of exchange received from the amount of exchange delivered.

Step 4: Identify Wheeled (Net)
Total the difference between the amount of energy entering your owned and or operated system for transmission through your system and the amount of energy leaving your system in MWh. Determine the energy losses on your system associated with the wheeling of energy for other systems.

Step 5: Identify Transmission by Others, Losses
Calculate the amount of energy losses in MWh associated with the wheeling of electricity provided to your owned and /or operated system by other utilities. Transmission by Others Losses should always be expressed as a negative value.

Step 6: Identify Total Sources
Calculate the sum of the energy sources (Net Generation, Purchases from Electricity Suppliers, Exchanges (Net), Wheeled (Net), and Transmission by Others, Losses).

Step 7: Identify Retail Sales to Ultimate Customers
Identify the amount of electricity in MWh sold to customers purchasing electricity for their own use and not for resale.

Step 8: Identify Sales for Resale
Determine the amount of electricity in MWh sold for resale purposes. This entry should include sales for resale to power marketers, full and partial requirements (firm) customers and to non-

requirements (nonfirm) customers.

Step 9: Identify Energy Furnished Without Charge
Identify the amount of electricity in MWh furnished by the electric utility without charge, such as to a municipality under a franchise agreement or for public street and highway lighting.

Step 10: Identify Energy Consumed Without Charge
Determine the amount of electricity in MWh used by the electric utility in its electric and other departments without charge.

Step 11: Identify Energy Consumed by Facility (Independent Power Producers or Qualifying Facility)
Calculate the amount of electric energy in MWh consumed at the facility in support of a service or manufacturing process.

Step 12: Identify Total Energy Losses
Identify the total amount of electricity lost from transmission, distribution, and/or unaccounted for. This is the difference between total sources, and the sum of Retail Sales to Ultimate Customers + Sales for Resale + Energy Furnished Without Charge + Energy Consumed by Respondent Without Charge + Energy Consumed by Facility (Independent Power Producers or Qualifying Facility). Total Energy Losses should always be expressed as a positive value.

Step 13: Identify T&D Loss Factor
Divide Total Energy Losses by Total Sources to identify the T&D Loss Factor in percentage terms.

Step 14: Identify Portion of Losses Attributable to Purchases and Wheeled Electricity
Multiply the T&D loss Factor by the "Total Purchases from Electricity Suppliers" and "Wheeled Received (In)" to calculate total T&D losses attributable to purchases and wheeled and record these values separately.

8.4.2 Indirect Emissions Associated with T&D Losses

Calculate indirect emissions associated with these T&D losses using the following six steps:

1. Identify the Weighted Average GHG Emission Factor of Power Purchases.
2. Identify the Weighted Average GHG Emission Factor of Wheeled Electricity.
3. Calculate Indirect CO_2 Emissions and Convert to Metric Tons.
4. Calculate Indirect CH_4 Emissions and Convert to Metric Tons.
5. Calculate Indirect N_2O Emissions and Convert to Metric Tons.
6. Convert GHG emissions to CO_2 Equivalents and Sum all Subtotals.

To calculate your weighted average emission factor, you must first determine the emission factor of each power purchase.

Step 1: Identify the Weighted Average GHG Emission Factors for Power Purchases
To determine a weighted average emissions factor for all electricity purchases, you must first determine the percentage of purchased power derived from each source (spot market, each facility, and each utility) and then multiply that percentage by each source-specific emission factor as illustrated in the equation below.

$$E= (S*S_f)+ (F* F_f) + (U* U_f)$$

Where: E=weighted average emissions factor for purchased power
S=proportion of power purchased from the spot market
S_f=average emission factor for spot purchases (power pool emission factor)
F=proportion of power purchased from a specific facility (for each facility)
F_f=facility-specific emission factor (for each facility)
U=proportion of power purchased from a specific utility (for each utility)
U_f=utility-specific emission factor (for each utility)
S+F+U=1

For any electricity purchase whose resources are known—i.e., purchased form a utility or a generator, you should use the GHG emission rate associated with that purchase. This can be the default emission factor from eGRID, or obtained directly from the generator.

If your company already tracks this information for compliance with state environmental disclosure rules, you may use this information to quantify the emissions factors associated with those purchases.

For any power purchased from the spot market, you should use the default emission factor.

Step 2: Identify the Weighted Average GHG Emission Factors for Wheeled Electricity
For wheeled electricity, if the particular generation resources are known, you should obtain the GHG emission factor of the power from the generator or utility, if available. If your company already tracks this information for compliance with state environmental disclosure rules, you may use this information to quantify the emissions factors associated with that wheeled electricity. If generator- or utility-specific emission factors are not available, use the default emission factors found in Table 8-2 (eGRID Subregion emission factors).

For all spot market power purchases, use the eGRID Subregion emission factors. For guidance regarding eGRID and emission factors resources, see the section below on emission factors.

To determine a weighted average emissions factor for all wheeled electricity, you must first determine the percentage of wheeled power derived from each source (known and unknown resources) and then multiply that percentage by each source-specific emission factor as illustrated in the equation below.

$$E= (K*K_f) + (U* U_f)$$

Where: W=weighted average emissions factor for wheeled power
K=proportion of power wheeled from known resources
k_f=average emission factor for known resources
U=proportion of power wheeled from a unknown resources
U_f=regional-specific emission factor (power pool emission factor)
K+U=1

Step 3: Calculate Indirect CO_2 Emissions and Convert to Metric Tons;
Once you have determined the weighted average CO_2 emission rates for purchased and wheeled power, multiply the MWh losses calculated in Step 2 by the applicable CO_2 emission rates. Sum all CO_2 emissions and convert to metric tons by dividing by 2,204.6.

Equation 8a	Determining Indirect CO_2 Emissions Associated with Purchased Power						
Total Indirect CO_2 Emissions from Purchased power (metric tons)	=	Total Losses Attributed to Purchases (MWh)	X	Weighted Average Emission Factor of Purchased Power (lbs CO_2/MWh)	/	2,204.6 lbs/metric ton	

While direct access is a portion of your wheeled power, to report to the Registry, you should distinguish the emissions from direct access from the rest of your wheeled power to provide greater transparency. Subtract your direct access from your wheeled power and calculate emissions from direct access separately.

Equation 8b	Determining Indirect CO_2 Emissions Associated with Wheeled Power						
Total Indirect CO_2 Emissions from Wheeled Power (metric tons)	=	Total Losses Wheeled Power (MWh)	X	Weighted Average Emission Factor of Wheeled Power (lbs CO_2/MWh)	/	2,204.6 lbs/metric ton	

Equation 8c	Determining Indirect CO_2 Emissions Associated with Direct Access						
Total Indirect CO_2 Emissions from Direct Access (metric tons)	=	Total Losses Direct Access (MWh)	X	Weighted Average Emission Factor of Direct Access (lbs CO_2/MWh)	/	2,204.6 lbs/metric ton	

Step 4: Calculate Indirect CH_4 Emissions and Convert to Metric Tons
Once you have determined the CH_4 emission rates, multiply the MWhs purchased and the MWhs wheeled by the applicable CH_4 emission rates. Sum all CH_4 emissions and convert to metric tons by dividing by 2,204.6.

Equation 8d	Determining Indirect CH_4 Emissions Associated with Purchased Power						
Total Indirect CH_4 Emissions from Purchased power (metric tons)	=	Total Losses Attributed to Purchases (MWh)	X	Weighted Average Emission Factor of Purchased Power (lbs CH_4/MWh)	/	2,204.6 lbs/metric ton	

Subtract your direct access from your wheeled power and calculate emissions from direct access separately.

Equation 8e	Determining Indirect CH_4 Emissions Associated with Wheeled Power					
Total Indirect CH_4 Emissions from Wheeled Power (metric tons)	=	Total Losses Wheeled Power (MWh)	X	Weighted Average Emission Factor of Wheeled Power (lbs CH_4/MWh)	/	2,204.6 lbs/metric ton

Equation 8f	Determining Indirect CH_4 Emissions Associated Direct Access					
Total Indirect CH_4 Emissions from Direct Access (metric tons)	=	Total Losses Direct Access (MWh)	X	Weighted Average Emission Factor of Direct Access (lbs CH_4/MWh)	/	2,204.6 lbs/metric ton

Step 5: Calculate Indirect N_2O Emissions and Convert to Metric Tons
Once you have determined the N_2O emission rates, multiply the MWhs of purchased and wheeled power by the applicable N_2O emission rates. Sum all N_2O emissions and convert to metric tons by dividing by 2,204.6.

Equation 8g	Determining Indirect N_2O Emissions Associated with Purchased Power					
Total Indirect N_2O Emissions from Purchased power (metric tons)	=	Total Losses Attributed to Purchases (MWh)	X	Weighted Average Emission Factor of Purchased Power (lbs N_2O/MWh)	/	2,204.6 lbs/metric ton

Subtract your direct access from your wheeled power and calculate emissions from direct access separately.

Equation 8h	Determining Indirect N_2O Emissions Associated with Wheeled Power					
Total Indirect N_2O Emissions from Wheeled Power (metric tons)	=	Total Losses Wheeled Power (MWh)	X	Weighted Average Emission Factor of Wheeled Power (lbs N_2O/MWh)	/	2,204.6 lbs/metric ton

Equation 8i	Determining Indirect N_2O Emissions Associated with Direct Access					
Total Indirect N_2O Emissions from Direct Access (metric tons)	=	Total Losses Direct Access (MWh)	X	Weighted Average Emission Factor of Direct Access (lbs N_2O/MWh)	/	2,204.6 lbs/metric ton

Step 6: Convert GHG Emissions to CO_2 Equivalents and Sum All Subtotals.
Once you have determined all the GHG emissions, convert the CH_4 and N_2O emissions into carbon equivalents using their global warming potentials (GWPs) and sum all CO_2 emissions.

Equation 8j	**Converting Mass Estimates to Carbon Dioxide Equivalent**		
Metric Tons of CO_2e	= Metric Tons of GHG	x	GWP

8.5 Indirect Emissions from Purchased and Wheeled Electricity

To determine your emission factor for your purchased electricity sold to end-users, you must first determine the emissions factor for your entire portfolio of purchased, wheeled power and direct access, or in other words, your entity-wide emissions factor. This should be a weighted average of known and unknown resources, including:

- **Facility-specific purchases**: When power purchase agreements (PPAs) create an agreement between a specific facility and a transmission/distribution company, the purchaser should use a facility-specific emissions factor.
- **Utility-specific purchases**: If you have a PPA with an electric utility that covers a number of facilities, you should use a utility-specific emissions factor
- **Spot market purchases**. Because spot market purchases cannot be traced back to a specific source and therefore do not have a unique or reliable emission factor, you should use the spot market emission factor.

As a first step in calculating your indirect emissions, you will need to know the appropriate emission factor for your purchased and wheeled power. These may come from either source- or supplier-specific emission factors, or average power pool-specific emission factors.

As a default, you may use average power pool numbers, listed in Table 8.2, provided from U.S. EPA's eGRID database.[13]

[13] The Emissions & Generation Resource Integrated Database (eGRID) provides information on the air quality attributes of almost all the electric power generated in the United States. eGRID provides search options including information for individual power plants, generating companies, states, and regions of the power grid. eGRID integrates 24 different federal data sources on power plants and power companies, from three different federal agencies: EPA, the Energy Information Administration (EIA), and the Federal Energy Regulatory Commission (FERC). Emissions data from EPA are carefully integrated with generation data from EIA to produce useful values like pounds per megawatt-hour (lbs/MWh) of emissions, which allows direct comparison of the environmental attributes of electricity generation. eGRID also provides aggregated data to facilitate comparison by company, state, or power grid region. eGRID's data encompass more than 4,700 power plants and nearly 2,000 generating companies. eGRID also documents power flows and industry structural changes. http://www.epa.gov/cleanenergy/egrid/index.htm.

Figure 8.1: eGRID Subregions

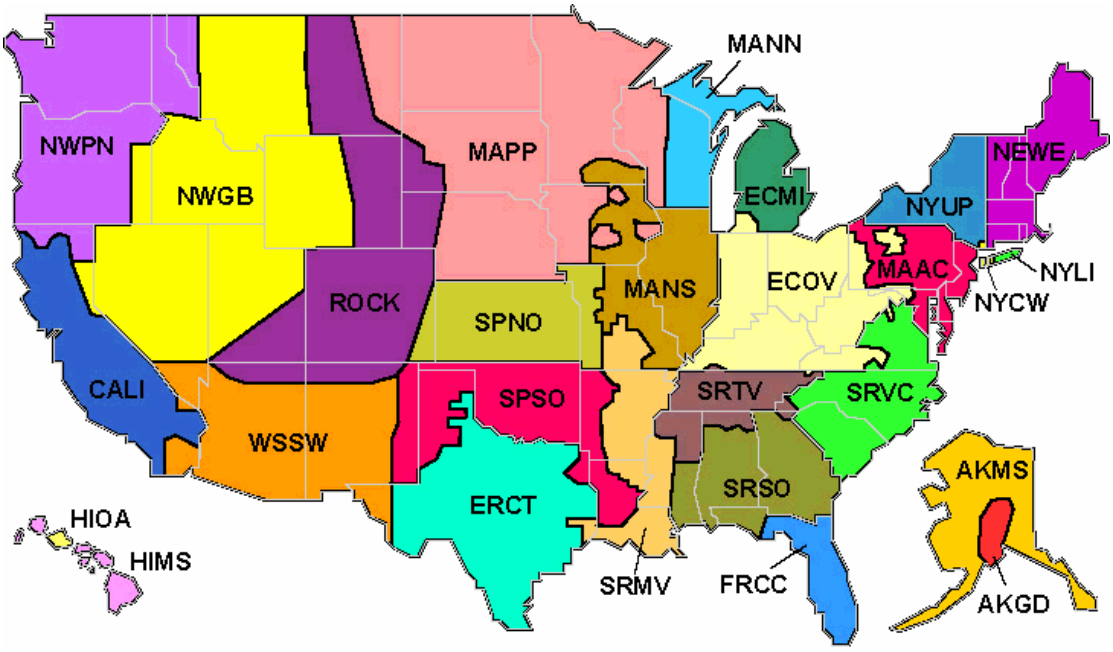

Table 8.2 eGRID Subregion Annual Average CO_2 Output-Based Emission Rates (Year 2000 – Total Energy)

eGRID Subregion Name	eGRID Subregion Acronym	CO_2 Output Emission Rate (lbs/MWh)
ASCC Alaska Grid	AKGD	1,399.95
ASCC Miscellaneous	AKMS	757.81
ECAR Michigan	ECMI	1,632.06
ECAR Ohio Valley	ECOV	1,966.53
ERCOT All	ERCT	1,408.27
FRCC All	FRCC	1,390.04
HICC Miscellaneous	HIMS	1,702.93
HICC Oahu	HIOA	1,721.69
MAAC All	MAAC	1,097.56
MAIN North	MANN	1,761.09
MAIN South	MANS	1,237.29
MAPP All	MAPP	1,838.83
NPCC Long Island	NYLI	1,659.76
NPCC New England	NEWE	897.11
NPCC NYC/Westchester	NYCW	1,090.13
NPCC Upstate NY	NYUP	843.04
Off-Grid	OFFG	1,706.71
SERC Mississippi Valley	SRMV	1,331.34
SERC South	SRSO	1,561.51
SERC Tennessee Valley	SRTV	1,372.70
SERC Virginia/Carolina	SRVC	1,164.19
SPP North	SPNO	2,011.15
SPP South	SPSO	1,936.65
WECC California	CALI	804.54
WECC Great Basin	NWGB	852.31
WECC Pacific Northwest	NWPN	671.04
WECC Rockies	ROCK	1,872.51
WECC Southwest	WSSW	1,423.95

eGRID2002 Version 2.01 Location (Operator)-Based eGRID Subregion File (Year 2000 Data)

8.5 Net Metering

If you have a net meter at your facility, you should report any on-site generation as direct stationary combustion. You should calculate your indirect emissions based on the portion of your electricity you purchase from the grid only.

Chapter 9: Industry-Specific Efficiency Metrics

What you will find in Chapter 9	This chapter provides guidance on determining what industry-specific metric(s) you must report to the Registry in addition to your entity-wide absolute emissions for your stated geographic area.
Information you will need	You may need information on your total annual emissions, total purchases and deliveries of electricity and/or natural gas.

9.1 Purpose of Reporting Industry-Specific Metrics

Normalized emissions are a ratio of your emissions compared to your output. The specific output measure depends on the nature of the organization that is reporting. Reporting normalized emissions allows trends in the carbon intensity of an activity to be gauged against a constant standard -- an organization's efficiency at producing a unit of output over time. The common terms for these measures are "efficiency metrics" or "carbon intensity metrics".

In considering a power generator or electric utility's emissions, any power producer may increase its generating capacity, increase its electric output to meet growing demand, and thus increase its total GHG emissions over time. However, as it grows, the power producer may also become more efficient at generating electricity. Industry observers may also be interested in comparing the environmental performance of power producers of different sizes, which is not easy to evaluate on the basis of absolute emissions.

For the purposes of this protocol, there are two main reasons for requiring the reporting of electric power and utility industry-specific metrics:

1. To provide a basis for consistent comparison across the industry regardless of entity size.

2. To track carbon intensity performance over time and complement the entity-wide absolute emissions reporting.

9.2 Mandatory Efficiency Metrics

For the electric power and utility sectors the following efficiency metrics must be reported:

1. *Total Energy Electricity Generation*: Pounds of direct CO_2 emissions from stationary fossil fuel combustion for electricity generation per net megawatt hour of electricity generated from all entity-owned or -controlled electric generating facilities (i.e., fossil fuel, renewable and nuclear) (lbs $CO_{2\text{Direct Fossil Fuel Stationary Combustion}}$/MWh$_{\text{Net Generated from All Energy Sources}}$);

2. *Fossil Fuel Electricity Generation*: Pounds of direct CO_2 emissions from stationary fossil fuel combustion for electricity generation per net megawatt hour of electricity generated from entity-owned or -controlled fossil-fuel fired electric generating facilities (lbs $CO_{2\text{ Direct Fossil Fuel Stationary Combustion}}$ /MWh$_{\text{Net Generated from Fossil Fuel Sources Only}}$);

3. *Total Electricity Deliveries*: Pounds of direct CO_2 emissions from stationary fossil fuel combustion for electricity generation and indirect CO_2 emissions from stationary fossil fuel combustion for electricity generation per net electricity generated by you and net electricity purchased from others for resale to end-users (lbs $CO_{2\text{ Direct Stationary Fossil Fuel Combustion and Indirect Stationary Fossil Fuel Combustion}}$ /MWh $_{\text{Net Generated and Net Purchased from all Energy Sources}}$).

Emissions that you have classified as de minimis should not be included in the calculations of

your efficiency metrics.

Which efficiency metric you must report depends on the nature of your business operations. More specifically:

- If your organization is vertically integrated (you own or control generation and transmission & distribution systems) you have fossil-fired generation, and you purchase electricity, you must report all three metrics.

- If your organization is vertically integrated (you own or control generation, electric transmission & distribution systems) and you purchase electricity but you have *no* fossil-fired generation, you must report all metrics except the fossil fuel-fired electricity generation metric.

- If you only own or control electric generation assets and do not purchase power from any other companies, you must report the two *electricity generation* metrics (i.e., Total Energy and Fossil Fuel).

If you have questions regarding which metrics you are required to report to the Registry, please contact the Registry.

If you are reporting only your California emissions, information on calculating these emissions is included below. For the generation metrics, you should include the emissions associated with your fuel combustion to generate and deliver to California at all facilities that you own, whether it is generated at facilities located inside or outside of California. For the delivery metric, you should include the emissions profile of all electricity that you generate, purchase and deliver to California.

9.3 Calculating Efficiency Metrics

To assist you in reporting these required metrics, the guidance below outlines the necessary steps to quantifying these metrics. For a discussion on optional metrics see Chapter 11 – Optional Reporting.

For power generators, the most significant source of emission comes from stationary fossil fuel combustion for electricity generation. For many power generators, fugitive, process and mobile sources may all or mostly be *de minimis*. Thus, to maintain consistency in comparing output efficiency, these metrics necessitate the use of the CO_2 emissions associated with the combustion of fossil fuel only in calculating your efficiency.

9.3.1 *Total Energy Electricity Generation*: Pounds of direct CO_2 emissions from stationary fossil fuel combustion per net megawatt hour of electricity generated from all entity-owned or -controlled electric generating facilities (i.e., fossil fuel, renewable, nuclear, etc.) (lbs $CO_{2\text{Direct Fossil Fuel Stationary Combustion}}/MWh_{\text{Net Generated from All Energy Sources}}$);

If you own or control electric generating facilities, report the pounds of carbon dioxide (CO_2) emitted from stationary fossil fuel combustion to generate electricity, per net megawatt hour generated on a total energy basis (including fossil fuel, non-emitting resources such as renewable energy and nuclear power).

To calculate this metric, follow these four steps:

Step 1: Sum all of your direct CO_2 emissions from stationary fossil fuel combustion for electricity generation at entity-owned or -controlled electric generation facilities.

- If you are reporting California emissions, and you own generation outside of California and deliver a portion of that generation to California customers, you must include the CO_2 emissions from fossil fuel combustion associated with all of the electricity that you generate and deliver to California customers.

  For instance, if you own a plant in Arizona that generates 1,000,000 MWh/year, of which 80% is delivered to California, you must calculate the emissions associated with the fuel consumed to generate 800,000 MWh of electricity.

Step 2: Sum all of the net electricity generation (MWh) associated with entity-owned or -controlled electric generation , and

- If you are reporting California emissions, and you own generation outside of California and deliver a portion of that generation to California customers, you must include the net electricity generation (MWh) that you generate and deliver to California customers.

Step 3: Divide the CO_2 emissions from Step 1 by the net electricity generation from Step 2.

Step 4: Convert to lbs. by multiplying by 2,204.6 lbs/metric ton.

Equation 9b	**Carbon Intensity of Entity Owned or Controlled Electricity Generation on a Total Energy Basis (lbs CO_2 Direct Fossil Fuel Stationary Combustion/MWh Net Generated from All Energy Sources**					
Total Energy Electricity Generation Metric (lbs CO_2/MWh)	=	Direct CO_2Emissions Associated with Stationary Fossil Fuel Combustion for Electricity Generation (metric tons CO_2)	/	Entity-Wide Electricity Generation (MWh Net Total Energy)	x	2,204.6 lbs/metric tons

9.3.2 *Fossil Fuel Electricity Generation*: Pounds of direct CO_2 emissions from stationary fossil fuel combustion for electricity generation per net megawatt hour of electricity generated from entity-owned or -controlled fossil-fuel fired electric generating facilities (lbs CO_2 Direct Fossil Fuel Stationary Combustion /MWh Net Generated from Fossil Fuel Sources Only)

If you own or control fossil fuel-fired electric generating facilities, report your pounds of direct CO_2 emissions from stationary fossil fuel combustion to generate electricity, per net megawatt hour generated of fossil fuel-fired generation, (i.e., coal, oil, natural gas, and diesel). The metric should be reported as lbs CO_2/MWh.

To calculate this metric, follow these four steps:

Step 1: Sum all of your CO_2 emissions from stationary fossil fuel combustion associated with the generation of electricity at entity-owned or -controlled electric generation facilities.

- If you are reporting California emissions, and you own fossil fuel-fired electricity generation outside of California and deliver a portion of that generation to California customers, you must include the CO_2 emissions from stationary fossil fuel combustion

associated with all of the electricity that you generate and deliver to California customers.

For instance, if you own a plant in Arizona that generates 1,000,000 MWh/year, of which 80% is delivered to California, you must calculate the emissions associated with the fossil fuel consumed to generate 800,000 MWh of electricity.

Step 2: Sum all of the net electricity generation associated with entity-owned or -controlled fossil fuel-fired electric generation in MWh, and

- If you are reporting California emissions, and you own fossil fuel-fired electricity generation outside of California and deliver a portion of that generation to California customers, you must include the net fossil fuel-fired electricity generation (MWh) that you generate and deliver to California customers.

Step 3: Divide the CO_2 emissions from Step 1 by the net fossil fuel-fired electricity generation from Step 2.

Step 4: Convert to lbs by multiplying by 2,204.6 lbs/metric ton.

Equation 9b	**Carbon Intensity of Entity Owned or Controlled Electricity Generation on a Fossil Fuel Only Basis (lbs CO_2 Direct Fossil Fuel Stationary Combustion /MWh Net Generated from Fossil Fuel Sources Only)**				
Fossil Fuel Only Electricity Generation Metric (lbs CO_2/MWh)	= Direct CO_2Emissions Associated with Stationary Fossil Fuel Combustion in Fossil Electricity Generation(metric tons CO_2)	/	Entity-Wide Fossil Electricity Generation (MWh Net Fossil Generation)	x	2,204.6 lbs/metric tons

9.3.3 *Total Electricity Deliveries*: Pounds of direct CO_2 emissions from stationary fossil fuel combustion for electricity generation and indirect CO_2 emissions from stationary fossil fuel combustion for electricity generation per net electricity generated at entity owned or controlled sources and net electricity purchased from others for resale to end-users (lbs CO_2 Direct Stationary Fossil Fuel Combustion and Indirect Stationary Fossil Fuel Combustion /MWh Net Generated and Net Purchased from all Energy Sources).

If you own or control electric generation and also purchase electricity for resale to end-users, report your lbs CO_2/MWh on a total energy basis including both net generated and net purchased power.

To calculate this metric, follow these five steps:

Step 1: Sum all of your direct CO_2 emissions from stationary fossil fuel combustion associated with the generation of electricity at entity-owned or -controlled electric generation facilities.

- If you are reporting California emissions, and you own generation outside of California and deliver a portion of that generation to California customers, you must include the CO_2 emissions from stationary fossil fuel combustion associated with all of the electricity that you generate and deliver to California customers.

Step 2: Sum all of your indirect CO_2 emissions associated with your power purchases.

Step 3: Sum your entity-wide net electricity generation and net purchased power for delivery to end-users in MWhs.

Step 4: Divide the CO_2 emissions from the sum of Step 1 and Step 2 by the net electricity generation from Step 3.

Step 5: Convert to lbs by multiplying by 2,204.6 lbs/metric ton. The equation is illustrated below.

Equation 9c

Carbon Intensity of Electricity Delivered to End Use Customers in California (lbs CO_2e Direct Stationary Fossil Fuel Combustion and Indirect Stationary Fossil Fuel Combustion /MWh Net Generated and Net Purchased from all Energy Sources).

Total Electricity Deliveries Metric (lbs CO_2/MWh = (Direct CO_2e Emissions from Stationary Fossil Fuel Combustion for Net Electricity Generation (metric tons CO_2) + Indirect CO_2e Emissions from Stationary Fossil Fuel Combustion Associated with Net Purchased Electricity (metric tons CO_2)) / (Entity-Wide Net Electricity Generation (MWh $_{Net\ Total\ Energy}$) + Net Purchased Electricity for Resale to End-users (MWh $_{Net\ Total\ Energy}$)) x 2,204.6 lbs/metric tons

9.4 Efficiency Metrics and Combined Heat and Power

Accounting for the GHG emissions from combined heat and power (CHP) is unique in the power/utility sectors because it produces more than one useful product from the same amount of fuel combusted, namely, electricity and heat or steam. As such, apportionment of the fuel and the GHG emissions between the two different energy streams is necessary. Most CHP systems capture the waste-heat from the primary electricity generating pathway and use it for climate control purposes, or to produce steam for other objectives. When the waste-heat is used directly to drive a thermal generator or to make steam that in turn drives an electric generator, these combined electricity production processes are grouped as a unit and called a combined cycle power plant. (The Registry treats emissions resulting from combined cycle power plants as stationary combustion emissions.) The steps below show how to distinguish emissions associated with power generation from other processes that use the waste-heat from electricity production.

The three most commonly-used methods to allocate emissions of CHP plants between the electric and thermal outputs are:

1. E*fficiency method*: On the basis of the energy input used to produce the separate steam and electricity products.

2. *Energy content method*: On the basis of the energy content of the output steam and electricity products.

3. *Work potential method*: On the basis of the exergy content of the steam and electricity products.

Table 9.1 Considerations in Selecting an Approach to CHP Emissions Allocation

Efficiency Method	• Allocates emissions according to the amount of fuel energy used to produce each final energy stream. • Assumes that conversion of fuel energy to steam energy is more efficient than converting fuel to electricity. Thus, focuses on the initial fuel-to-steam conversion process. • Actual efficiencies of heat and of power production will not be fully characterized, necessitating the use of assumed values.
Energy Content Method	• Allocates emissions according to the useful energy contained in each CHP output stream • Need information regarding the intended use of the heat energy. • Best suited where heat can be characterized as useful energy, e.g., for process or district heating. • May not be appropriate where heat used for mechanical work because it may overstate the amount of useful energy in the heat, resulting in a low emissions factor associated with the heat stream.
Work Potential Method	• Allocates emissions based on the useful energy represented by electric power and heat, and defines useful energy on the ability of heat to perform work. • Appropriate when heat is to be used for producing mechanical work (where much of the heat energy will not be characterized as useful energy). • May not be appropriate for systems that sell hot water because hot water cannot be used, as steam can, to perform mechanical work.

In order to insure a consistent approach in the power/utility sector to allocating GHG emissions in CHP applications, the Registry recommends the use of the **efficiency method**. A default quantification methodology is provided below for this method. For more information on alternative CHP methods, see the GRP and the GHG Protocol.[14]

9.5 Efficiency Method

For this method, emissions are allocated based on the separate efficiencies of steam and electricity production. Use the following steps to determine the share of CO_2 emissions attributable to steam and electricity production:

Step 1: Determine the total direct emissions and the total steam and electricity output for the CHP system.

Calculate total direct GHG emissions using Equation 9e below.

Steam tables provide energy content (enthalpy) values for steam at different temperature and pressure conditions. Enthalpy values multiplied by the quantity of steam give energy output values. Obtain the steam energy content values from the IAPWS-IF97 steam tables.[15]

To convert electricity output to MMBtu, sum your net electricity generation in MWhs and multiply that value by 3.415.[16]

[14] WRI/WBCSD GHG Protocol Corporate Accounting and Reporting Standard (Revised Edition).

[15] IAPWS Industrial Formulation 1997 for the Thermodynamic Properties of Water and Steam (IAPWS-IF97), International Association for the Properties of Water and Steam. This publication replaces the previous industrial formulation, IFC-67.

[16] MWh to MMBtu conversion source – Energy Information Administration (EIA), *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996), Appendix B.

Equation 9e	Total CO_2 Emissions (Fuel Consumption is in MMBtu)					
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CO_2/MMBtu)	X	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg

Combine the steam and electricity outputs into one energy output value, expressed in the same units of energy (MMBtu) using Equation 9f below.

Equation 9f	Total Energy Output (in MMBtu)			
Total Energy Output (MMBtu)	=	Steam Output (MMBtu)	+	Electricity Output (MMBtu)

Step 2: Determine the efficiencies of steam and electricity production.
Identify steam efficiencies. If actual efficiencies are not known, use default values of 80% for steam. Identify electricity efficiencies. If actual efficiencies are not known, use default value of 35% for electricity.

Step 3: Determine the fraction of total emissions to allocate to steam and electricity production.
Calculate the portion of your total emissions associated with steam using the following formulas:

$$E_H = \frac{H/e_H}{H/e_H + P/e_P} * E_T \quad \text{and} \quad E_P = E_T - E_H$$

where:

E_H	=	emissions allocated to steam production
H	=	steam output (energy)
e_H	=	assumed efficiency of steam production
P	=	delivered electricity generation (energy)
e_P	=	assumed efficiency of electricity generation
E_T	=	total direct emissions of the CHP system
E_P	=	emissions allocated to electricity production

Note: The use of default efficiency values may, in some cases, violate the energy balance constraints of some CHP systems. However, total emissions will still be allocated between the energy outputs. Nevertheless, you should be aware of the energy balance. If the constraints are not satisfied e_H and e_P can be modified until constraints are met.

Step 4: Calculate emission rates for steam and electricity production.
Divide the total CO_2 emissions from steam production (Step 3) by the total amount of steam produced to get an emission rate of pounds of carbon dioxide equivalents per thousand pounds of steam produced (lbs CO_2e/Mlbs of steam).

Equation 9g	Emission Rate for Steam Production (lbs CO_2e/Mlbs of steam)					
Emission Rate for Steam Production (lbs CO_2e/Mlbs of steam)	=	Total CO_2e Emissions from Steam Production (metric tons CO_2e)	/	Total Quantity of Steam Produced (Mlbs of steam)	x	2,204.6 lbs CO_2e/metric ton

Divide the total CO_2 emissions from electricity production (Step 3) by the total amount of electricity produced to get an emission rate of pounds of carbon dioxide equivalents per megawatt hour generated (lbs CO_{2e}/MWh).

Equation 9h	Emission Rate for Electricity Production (lbs CO_2e/MWh)					
Emission Rate for Electricity Production (lbs CO_2e/MWh)	=	Total CO_2e Emissions from Electricity Production (metric tons CO_2e)	/	Total Quantity of Electricity Produced (MWh)	x	2,204.6 lbs CO_2e/metric ton

Step 5: Estimate CO_2 emissions from purchases or sales.
To estimate emissions, multiply the amount of steam or electricity either purchased or sold by the appropriate emission rate (Step 4). Note: units used to report steam or electricity should be the same units as used to calculate the emission rates.

Equation 9i	Total CO_2 Emissions (Fuel Consumption is in MMBtu)					
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CO_2/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg

Chapter 10: Calculating De Minimis Emissions

What you will find in Chapter 10	This chapter provides guidance on estimating emissions that may be *de minimis* in quantity.
Information you will need	You may need information on your total annual emissions, total purchases and deliveries of electricity and/or natural gas.

For many power/utility entities the administrative effort associated with identifying, quantifying, and reporting all of their GHG emissions could be unduly burdensome and not cost-effective.

You must report at least 95% of your total emissions. To reduce the reporting burden, each participant can declare up to 5% of their total emissions as *de minimis*. *De minimis* emissions must be estimated and reviewed by the certifier, but do not need to be publicly reported.

While the sources and gases that will be *de minimis* will vary from participant to participant, your estimates must be conservative, verifiable, and appropriately documented. You should estimate *de minimis* emissions using "rough upper bounds" estimates (since the amounts may be insignificant even as upper bounds). Your estimations and assumptions in calculating your *de minimis* emissions will need to be provided to and reviewed by your certifier.

If your operations do not change significantly from year to year, you will only need to re-calculate and have reviewed your *de minimis* emissions every three years. For certification purposes, records and documentation that support the *de minimis* calculations should be made available to the certifier.

10.1 Calculating *De Minimis* Emissions

The following calculations provide acceptable conservative methods for illustrating *de minimis* emissions for power/utility entities. These examples assume an entity that has entity-wide emissions of 3 million tons of CO_2e which means that it can identify a mix of sources as *de minimis* up to a total of 150,000 tons of CO_2e.

10.1.1 Stationary Combustion Sources

In certain circumstances, power/utility entities may not have the necessary fuel use data for small combustion sources to estimate emissions according to the PUP. Where limited data exists for small combustion sources, conservative engineering estimates are an acceptable method for quantifying GHG emissions and illustrating whether these emissions are *de minimis*.

Estimate your direct CO_2 emissions from stationary combustion sources using the following process:

1. Identify the operating parameters of the source;

2. Identify the appropriate emission factor based on fuels combusted in the source; and

3. Calculate CO_2 emissions and convert to metric tons;

Each of these steps is described in greater detail below.

Step 1: Identify the Operating Parameters of the Source
Use company records to identify the capacity of the piece of equipment along with conservative assumptions about operating hours and fuel use to calculate emissions.

Step 2: Identify the Appropriate Emission Factor Based on Fuel Combusted in the Source
Use the default emission factors provided in Chapter 5 (Stationary Combustion) to calculate CO_2 emissions associated with the source.

Step 3: Calculate CO_2 Emissions and Convert to Metric Tons
Use the default emission factors identified to calculate CO_2 emissions associated with the source and divide the number of lbs CO_2 obtained by 2,204.6 lbs/metric ton to obtain metric tons of CO_2 produced.

Example 10-1: Calculating De Minimis Emissions from Stationary Combustion Sources

Company A has an oil-fired auxiliary boiler (Boiler X) with a nameplate capacity of 2 mmBtu/hr. The boiler has no fuel meter. The boiler is used only for plant startups and quarterly operational checks.

Estimate the emissions from Boiler X:

Step 1: Identify the Operating Parameters of the Source
In a typical year no more than two or three plant startups occur. Quarterly checks and startups are assumed to last for five hours with Boiler X operating at full capacity. To achieve a conservative estimate of emissions from Boiler X, assume five plant startups and four quarterly operational checks for a total of nine operating times or 45 hours total.

45 hours x 2 mmBtu/hr = 90 mmbtu

Step 2: Identify the Appropriate Emission Factor Based on Fuel Combusted in the Source

Oil-fired auxiliary boiler with nameplate capacity of 2 mmBtu/hour = 78.79 kg CO_2/mmBtu

Step 3: Calculate CO2 Emissions and Convert to Metric Tons

90 mmBtu x 78.79 kg CO_2/mmBtu x 0.001 metric tons/kg = 7.0911 metric tons CO_2

10.1.2 Fugitive CH_4 Emissions from Fuel Handling and Storage

Handling and storage of some fuels may be a source of fugitive CH_4 emissions. For instance, different types of coals desorb methane at different rates, but since coal is usually removed from a mine within hours or days of being mined, some methane remains and is liberated from the coal during handling operations. Fugitive emissions such as these are likely *de minimis* for most entities.

At this time, there is no guidance provided in the PUP to complete a *de minimis* calculation for fugitive emissions from biomass fuel use and handling. However, in the future a method may be identified based on guidance from the CA Registry Forestry Protocol.

A methodology is presented below to help you conservatively estimate fugitive CH_4 emissions associated with coal handling and storage. This method uses U.S. EPA-established emission factors for coals that encompass all post-mining activities, including storage in piles at the utilities.

Estimate your fugitive CH_4 emissions using the following process:

1. Identify the Total Tons of Coal Purchased.
2. Identify the Appropriate Emission Factor Based on Coal Origin.
3. Calculate Fugitive CH_4 emissions and Convert to metric tons.
4. Convert CH_4 emissions to CO_2 equivalents and sum all subtotals.

Each of these steps is described in greater detail below.

Step 1: Identify the Total Tons of Coal Purchased
Consult purchase records to identify the total quantity of coal purchases that originate from underground and surface mines.

Step 2: Identify the Appropriate Emission Factor Based on Coal Origin
Use the default emission factors noted in Table 10.1 below to calculate fugitive methane emissions associated with the fuel handling and storage of the coal.

Table 10.1: Weighted Average Post Mining Fugitive CH_4 Emission Factors for Coal

Coal Mine Type	Emission Factor (scf CH4/ton)
Underground	44.3
Surface	4.8

Step 3: Calculate Fugitive CH_4 Emissions and Convert to Metric Tons
Convert from standard cubic feet of methane to lbs of methane by multiplying by 42.28 lbs CH_4 per standard cubic feet of methane. Divide the number of lbs CH_4 obtained by 2,204.6 lbs/metric ton to obtain metric tons of CH_4 produced.

Equation 10a	**Determining Total Annual Fugitive Methane Emissions**					
Total Fugitive Emissions of CH_4 (metric tons)	=	Fugitive Methane Emissions (scf)	**X**	.04228 lbs CH_4/scf	/	2,204.6 lbs/metric ton

Step 4: Convert CH_4 Emissions to CO_2 Equivalents and Sum all Subtotals
To incorporate and evaluate non-CO_2 gases in your GHG emissions inventory, the mass estimates of these gases will need to be converted to CO_2 equivalent. To do this, multiply the emissions in units of mass by CH_4's GWP. If non-CO_2 gases are de minimis when converted to CO_2e, you do not need to report them to the Registry. Also, you are not required to report non-CO_2 gases until the fourth year that you report emissions to the Registry.

Equation 10b	**Converting Mass Estimates to Carbon Dioxide Equivalent**			
Metric Tons of CO_2e	=	Metric Tons of GHG	x	GWP

Example 10-2: Calculating De Minimis Emissions from Coal Piles

In a typical year, Company A purchases 1 million tons of coal.

To achieve a conservative estimate of fugitive emissions from coal purchases, Company A assumes that all the coal originates from underground mines.

Step 1: Identify total tons of coal purchased: 1 million tons

Step 2: Identify the appropriate emission factor based on coal origin and multiply by total tons of coal purchased:

Coal Mine Type	Emission Factor (scf CH4/ton)
Underground	44.3

1,000,000 tons x 44.3 scf/CH4.ton = 44,300,000 scf CH4

Step 3: Calculate fugitive CH4 emissions and convert to metric tons.

Equation 10a	Determining Total Annual Fugitive Methane Emissions					
17,841 metric tons (CH_4)	=	44,300,000 scf Fugitive Methane Emissions	**X**	.04228 lbs CH_4/scf	/	2,204.6 lbs/metric ton

Step 4: Calculate total Global Warming Potential

Equation 10b	Convert Mass Estimates to Carbon Dioxide Equivalent		
374,661 Metric Tons of CO_2e	=	17, 841 Metric Tons CH_4	x 21 (GWP)

10.2 Selecting *De Minimis* Sources

Once you have estimated all of the sources you believe are de minimis, you need to determine if they are indeed less than 5% of your total emissions.

Step 1: Total emissions from all estimated de minimis sources.

Step 2: Divide your total emissions by your total estimated de minimis emissions.
If the total is less than 5%, all of your estimated emissions may be classified as de minimis. If your total is greater than 5%, you must assess which emissions you will obtain the necessary information to calculate, report and have certified. You should classify your sources from largest to smallest, and report the emissions from the largest of the "de minimis" sources.

Chapter 11: Optional Reporting

What you will find in Chapter 11	This chapter provides limited guidance on reporting additional information on specific activities to reduce your total emissions footprint.
Information you will need	You may need information on your total annual emissions, total purchases and deliveries of electricity and/or natural gas.

In order to certify an emissions report with the California Climate Action Registry program, some categories of emissions are required. These include emissions from direct sources: stationary combustion, mobile combustion, fugitive emissions, process emissions. These also include indirect emissions associated with electricity, steam, heating and cooling that is purchased and consumed. For purposes of this program, *all other categories of information are considered optional. Because there are no protocols governing optional reporting, the optional reporting information is not eligible for certification within the CA Registry. The State of California will only back certified information reported to the CA Registry.*

The Registry encourages its participants to provide additional information, e.g., emissions associated with product shipping, employee commuting and business travel, etc. Measuring such kinds of information will help each participants understand the full impact of the climate of their business activities. You may also want to include references to your organization's environmental goals, policies, programs and performance. This information can showcase your environmental efforts, including emission reduction projects. Also, you can provide links to external sources to allow viewers to learn more about your environmental programs. This optional reporting section allows power/utility entities to create a public record of other activities that may complement the emissions inventory.

This chapter outlines some limited guidance for optional reporting areas relevant to electric power generators and electric utilities to serve as a starting point for your effort to identify,and calculate emissions from other activities of your organization.

11.1 Other Reporting

Other activities that you may choose to report include:

- **Indirect emissions from extraction, production, and transportation of fuels used for generation of electricity, heat, or steam.** This includes the upstream emissions associated with the extraction and production of fuels used to generate electricity. Examples include emissions from mining of coal, and extraction of natural gas.

- **Purchases and sales of tradable renewable certificates (TRC)**. At a minimum, you should report the quantity of TRCs purchased or sold in a given year, the purpose(s) of the purchase and sales, and the geographic origin of the TRCs. You should also identify the other registries and/or regulatory agencies to which you have reported this information.

- **Annual energy efficiency savings.** You should report megawatts of peak load saved and total electricity saved annually in megawatt-hours. You should also report the reason for undertaking the energy efficiency programs (regulatory requirements, demand response, voluntary, etc), and to which other registries and/or regulatory agencies you have reported this information.

- **Purchases and sales of GHG emission offset projects.** At a minimum, you should report the type of project(s) and the quantity of emission reductions. You should also report the terms of the purchase and/or sale and to which other registries and/or regulatory agencies you have reported this information.

- **Contractual agreements assigning liability.** You should report the details of the specific contractual agreements including: the parties involved, the scope of the agreement, and the duration of the agreement. You should also report to which other registries and/or regulatory agencies you have reported this information.

11.2 Optional Metrics

You may also report optional efficiency metrics as part of your Annual GHG Emission Report to the Registry to highlight aspects of your environmental performance. The following efficiency metrics may be reported along with entity-wide emissions.

- *Energy Output*: Pounds of direct carbon dioxide equivalent emissions per million British Thermal Units of energy output from all entity-owned or -controlled assets and facilities (lbs. CO_2e_{Direct}/MMBtu $_{Direct}$);

- *Natural Gas Deliveries*: Pounds of direct carbon dioxide equivalent emissions per therm of natural gas delivered from entity-owned or -controlled natural gas transmission, storage and/or distribution assets (lbs. CO_2e_{Direct}/Therm).

- *Fuel- or Facility*: If you own or control electric generating facilities you may report pounds of carbon dioxide equivalent per megawatt hour generated (lbs CO_2e/MWh) on a fuel-specific basis or facility-specific basis.

- *Electricity by Customer Type*: If you own or control electric transmission & distribution assets you may report lbs CO_2e/customer by customer type (residential, commercial, industrial).

- *Natural Gas by Customer Type*: If you own or control natural gas transmission & distribution assets you may report lbs CO_2e/customer by customer type (residential, commercial, industrial).

If your organization is vertically integrated (you own or control generation, transmission, and distribution systems) such as in investor-owned utilities, then you may report any combination of the metrics outlined above.

Guidance is provided, for your reference, on calculating two of these optional metrics. These methodologies are provided for your information only. However, these metrics are not currently eligible for certification under the Registry program.

11.2.1 *Energy Output*: Pounds of direct CO_2e emissions per million British Thermal Units of energy output from all entity-owned or controlled assets and facilities (lbs. CO_2e_{Direct}/MMBtu $_{Direct}$)

All power/utility entities reporting to the Registry must report this entity-wide metric, which incorporates all of your required direct emissions including:

- stationary combustion from the onsite production of heat, steam, or electricity owned or

controlled by your organization;
- fugitive leaks or venting from operations owned or controlled by your organization including:
  1. natural gas systems
  2. electricity transmission and/or distribution systems,
  3. air conditioning and refrigeration systems, and
  4. fire suppression equipment;
- processes such as emission control technologies and other activities that are owned or controlled by your organization; and
- mobile combustion from non-fixed sources that are owned or controlled by your organization.

To calculate this entity-wide metric, follow these four steps:

Step 1: Sum all of your entity-wide direct CO_2e emissions. Include all the direct emissions from stationary and mobile combustion, fugitive leaks and venting, and processes.

Step 2: Sum your total natural gas deliveries in therms and convert to million British thermal units (MMBtu) by multiplying by 0.1.[17]

Step 3: Sum your net electricity generation in MWhs and convert to MMBtu by multiplying by 3.412.[18]

Step 4: Sum total entity-wide MMBtu and divide the direct CO_2e emissions from Step 1 by the entity-wide MMBtu.

Step 5: Convert to lbs. by multiplying by 2,204.6 lbs/metric ton. The equation is illustrated below.

Equation 9a	**Entity-wide Carbon Intensity Metric (lbs CO_2e_{Direct}/MMBtu)**							
Carbon Intensity Metric – Entity-wide (lbs CO_2e/MMBtu)	=	Entity-wide Direct CO_2e Emissions (metric tons CO_2e)	/	Natural Gas Deliveries (MMBtu)	+	Net Electricity Generation (MMBtu)	x	2,204.6 lbs/metric tons

11.2.2 *Natural Gas Deliveries*: Pounds of direct CO_2e emissions per Therm of natural gas delivered from entity-owned or controlled natural gas transmission, storage and/or distribution assets (lbs. CO_2e_{Direct}/Therm)

If you own or control natural gas transmission, storage and/or distribution assets you shall report lbs. CO_2e/therm of natural gas delivered to end-users.[19]

To calculate this metric, follow these four steps:

Step 1: Sum all of your direct CO_2e emissions from your natural gas transmission, storage, and/or distribution system. Include all the direct emissions associated with the physical natural

[17] Therm to MMBtu conversion source – Energy Information Administration (EIA), *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996), Appendix B.
[18] MWh to MMBtu conversion source – Same as above.
[19] A therm is 100,000 Btus and is the unit most often used by distribution companies. One decatherm (Dth) is 10 therms, or one MMBtu (one million Btu).

gas system you own or control including: stationary combustion activities, fugitive emissions of methane (CH_4) and CO_2, and vented emissions.

Step 2: Sum your total natural gas deliveries to end-users in therms.

Step 3: Divide the CO_2e emissions from Step 1 by the therms of natural gas deliveries to end-users from Step 2.

Step 4: Convert to lbs. by multiplying by 2,204.6 lbs/metric ton. The equation is illustrated below.

Equation 9d	**Carbon Intensity of Natural Gas Delivery (lbs CO_2e_{Direct}/Therm)**				
Carbon Intensity Metric – Natural Gas (lbs CO_2e/Therm)	=	Direct CO_2e Emissions Associated with Natural Gas System (metric tons CO_2e)	/	Natural Gas Deliveries to End Use Customers (Therm)	x 2,204.6 lbs/metric tons

Congratulations! Once you have completed calculating your GHG emissions according to the guidance in this appendix, return to the General Reporting Protocol for details on completing your report, using CARROT, and beginning certification.

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Annex A: EPA Method For Estimating SF6 Emissions from Electrical Equipment Used by Utilities

This worksheet is based on the mass-balance method. The mass-balance method works by tracking and systematically accounting for all company uses of SF_6 during the reporting year. The quantity of SF_6 that cannot be accounted for is then assumed to have been emitted to the atmosphere. The method has four subcalculations (A-D) and a final total (E)

A. Decrease in Inventory. This is the difference between the quantity of SF_6 in storage at the beginning of the year and the quantity in storage at the end of the year. The "quantity in storage" includes SF_6 gas contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not refer to SF6 gas held in operating equipment. The decrease in inventory will be negative if the quantity of SF6 in storage increases over the course of the year.

B. Purchases/Acquisitions of SF_6. This is the sum of all the SF_6 acquired from other entities during the year either in storage containers or in equipment.

C. Sales/Disbursements of SF_6. This is the sum of all the SF_6 sold or otherwise disbursed to other entities during the year either in storage containers or in equipment.

D. Increase in Total Nameplate Capacity of Equipment. This is the net increase in the total volume of SF_6-using equipment during the year. Note that "total nameplate capacity" refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage. This term accounts for the fact that if new equipment is purchased, the SF_6 that is used to charge that new equipment should not be counted as an emission. On the other hand, it also accounts for the fact that if the amount of SF_6 recovered from retiring equipment is less than the nameplate capacity, then the difference between the nameplate capacity and the recovered amount has been emitted. The Increase in Total Nameplate Capacity of Equipment will be negative if the retiring equipment has a total nameplate capacity larger than the total nameplate capacity of the new equipment.

E. Total Annual Emissions. This is the total amount of SF_6 emitted over the course of the year, based on the information provided above. The amount is presented both in pounds of SF_6 and in metric tons of CO_2-equivalent, that is, the quantity of carbon dioxide emissions that would have the same impact on the climate as the quantity of SF_6 emitted. Because SF_6 has 23,900 times the ability of carbon dioxide to trap heat in the atmosphere on a pound-for-pound basis, 1 pound of SF6 is equivalent to nearly 11 tons of carbon dioxide.

F. Emission Rate (optional). By providing the total nameplate capacity of <u>all</u> the electrical equipment in your facility at the end of the year, you can obtain an estimate of the emission rate of your facility's equipment (in percent per year). The emission rate is equal to the total annual emissions divided by the total nameplate capacity.

Change in Inventory (SF_6 contained in cylinders, <u>not</u> electrical equipment)

Inventory (in cylinders, **not** equipment)	AMOUNT (lbs.)	Comments
1. Beginning of Year		
2. End of Year		
A. Change in Inventory (1 - 2)	-	

Purchases/Acquisitions of SF_6

	AMOUNT (lbs.)	Comments
3. SF_6 purchased from producers or distributors in cylinders		
4. SF_6 provided by equipment manufacturers with/inside equipment		
5. SF_6 returned to the site after off-site recycling		
B. Total Purchases/Acquisitions (3+4+5)	-	

Sales/Disbursements of SF_6

	AMOUNT (lbs.)	Comments
6. Sales of SF_6 to other entities, including gas left in equipment that is sold		
7. Returns of SF_6 to supplier		
8. SF_6 sent to destruction facilities		
9. SF_6 sent off-site for recycling		
C. Total Sales/Disbursements (6+7+8+9)	-	

Change in Nameplate Capacity

	AMOUNT (lbs.)	Comments
10. Total nameplate capacity (proper full charge) of <u>new</u> equipment		
11. Total nameplate capacity (proper full charge) of <u>retired</u> or <u>sold</u> equipment		
D. Change in Capacity (10 - 11)	-	

Total Annual Emissions

	lbs. SF_6	Tonnes CO_2 equiv. (lbs.SF_6x23,900/2205)
E. Total Emissions (A+B-C-D)	-	-

Emission Rate (optional)

	AMOUNT (lbs.)	Comments
Total Nameplate Capacity at End of Year		
	PERCENT (%)	
F. Emission Rate (Emissions/Capacity)	-	

Appendix D to the General Certification Protocol: Power/Utility Certification Protocol

Guidance for Certification of Entity-Wide Greenhouse Gas Emissions Produced by Electric Power Generators and Electric Utilities

1.0 Power/Utility Certification Protocol

The Power/Utility Certification Protocol (PUCP) is an appendix to the General Certification Protocol. The intended audience for this Appendix is approved power/utility sector certifiers. However, power/utility entities may also find it useful to review this Appendix to develop a better understanding of the certification activities associated with power/utility sector reporting in the California Climate Action Registry (Registry).

This PUCP provides guidance for reviewing and certifying the portions of a power/utility entity's inventory that are significant and/or unique to the activities of electric power generators and electric utilities. These include:

- Indirect emissions associated with wholesale electricity and fuel transactions;
- Stationary combustion emissions from generation of electricity, heat and steam;
- Fugitive emissions from natural gas transmission, storage and distribution; and
- SF_6 emissions from electricity transmission and distribution.

For activities not unique to power generators and electric utilities, reporting guidance is found in the General Reporting and Certification Protocols.

All Registry members report using the General Reporting Protocol and where available, any industry-specific protocols. All certifiers should conduct certifications using the General Certification Protocol and any available industry-specific requirements.

To conduct power/utility certifications, power/utility certifiers must read and be familiar with the following Registry reporting tools:

- General Reporting Protocol (GRP),
- General Certification Protocol (GCP),
- Power/Utility Reporting Protocol (PUP),
- Power/Utility Certification Protocol (PUCP), and
- Climate Action Registry Reporting Online Tool (CARROT).

These tools are all available on the Registry's website at www.climateregistry.org. If you have difficulty accessing any of the documents, please call 213-891-1444.

The Registry's general and industry-specific reporting and certification protocols are designed to be compatible with each other. Should you encounter a conflict between any of the documents, or if you have questions about carrying out the steps described herein, please contact the Registry at: 1-877-CO2-CCAR.

To provide formal comments or suggestions to the Registry, please complete and submit a *Protocol Comment Form*, available at www.climateregistry.org/Protocols. Comments will be posted on the Registry website for public review and response.

The Registry may update the PUP and PUCP occasionally to reflect new scientific findings or policy direction. The Registry will notify all power/utility entities and approved power/utility sector certifiers when it updates the documents. The current versions of all protocols will always be available on the Registry's website: www.climateregistry.org/protocols.

***Please Note**: Only State- and Registry-approved power/utility sector certifiers are eligible to certify power/utility entities, as defined by NAICS code in the PUP. It is important to note that State- and Registry- approved certifiers under the Registry's General Reporting Protocol are* not *automatically approved to certify power/utility entities. To become an approved power/utility sector certifier, a general certifier must successfully complete a power/utility sector-specific application process. The complete list of power/utility sector certifiers and information on the application process is available at www.climateregistry.org/certifiers*

1.1 Standard for Certification for Electric Power Generators and Electric Utilities

The Registry's standard for power/utility sector certification is its General Reporting Protocol and its Power/Utility Protocol (PUP). The PUP contains the Registry's required sources of direct and indirect emissions, default emission factors and GHG calculations, and is the basis for evaluating whether an entity's reported GHG emissions are reported appropriately. You should only apply the standards described in the GRP, GCP, PUP and this PUCP when assessing a power/utility participant's annual GHG Report to the Registry.

1.2 The Certification Process

The Registry's 10 step certification process is explained in detail in the General Certification Protocol. The guidance in this document must be followed when completing Steps 6 (Conducting Certification Activities) and Step 7 (Certification Documentation) of the certification process.

1.2.1 Required Reporting Elements

A certified power/utility emission report must include all of a participant's significant emissions within the following categories:

Direct Emissions

- Stationary Combustion Emissions
- Mobile Combustion Emissions
- Process Emissions
  - from SO_2 Scrubbers
  - from other processes

Fugitive Emissions

- From Electricity Transmission and Distribution Systems
- From Natural Gas Transmission, Storage and Distribution systems.
- From Fuel Handling and Storage

Indirect Emissions

- o Purchased electricity, heat and steam for own consumption
- o Electricity Transmission & Distribution Losses

Industry-Specific Metrics

- Electricity Generated (lbs $CO_2e_{\text{Fuel Used inDirect Stationary Combustion}}$ /$MWh_{\text{Net Generated}}$);
- Fossil Electricity Generated (lbs $CO_2e_{\text{Fuel Used inDirect Stationary Combustion}}$ /$MWh_{\text{Net Fossil Generated}}$); and
- Electricity Delivered (lbs $CO_2e_{\text{Fuel used in Direct Stationary Combustion and Purchased Electricity}}$ /$MWh_{\text{Net Generated and Net Purchased}}$)

1.2.2 Optional Reporting Elements

An annual GHG Emission Report may also contain additional optional information. This could include, for instance, information about a company's environmental policies and goals, renewable energy certificate purchases, purchase power contracts, additional metrics, etc. All non-required GHG data is optional, and does not require certification. Optional information should not be considered in assessing the quality of the required emissions information. Optional information will be clearly distinguished from required information in the CARROT.

2.0 Core Certification Activities: Power/Utility Entities

In addition to the requirements and process outlined in the General Certification Protocol, specific guidance for conducting power/utility entity certification activities for each of the core certification activities follows.

To confirm that power/utility entity GHG emissions have been reported accurately, you should review the appropriate documents listed in Table 1 as part of your certification activities.

Note that the documentation list in Table 1 is provided by core certification activity as a reference for both you and the power/utility entity. Prior to your first meeting with the power/utility entity you should review and identify for the entity documents you would like to access in order to expedite the certification process. You may also want to provide a list of documents that you deem necessary to complete the certification. (You may determine the need to request additional documents in the course of completing the certification).

Table 1. Documents for Review During Certification Activities

Activity or Emissions Source	Documents
Step 1: Identifying Emission Sources	
Emission Source Inventory	CARROT Report Facility Inventory List of Facility Permits Facility Plot Plans Showing Direct Emission Sources Process Flow Diagrams Fuel Purchases Records, by fuel type State Emission Inventory Reports EPA Acid Rain Reports
Organizational, Operational and Geographic Boundaries	List of Emission Sources, including: • Stationary Sources • Mobile Sources • Fugitive Sources • Process Emission Sources Security and Exchange Commission (SEC) Form 10k Federal Energy Regulatory Commission (FERC): Form 1 Annual Report of Major Electric Utility Form 2 Major Natural Gas Pipeline Annual Report Energy Information Administration: Forms 176, 191, 412, 423, 767, 857, 860, 861, 906, 920 State Public Utility Commission Filings Corporate Annual Reports Map of Operations
Step 2: Understanding Management Systems and Methodologies	
Data Management Systems	Location of Data Collection System (centralized or decentralized) Type of Management System and Parameters Tracked Data Acquisition and Handling System
Responsibilities for Implementing GHG Management Plan	Entity Organization Chart Greenhouse Gas Management Plan Documentation and Retention Plan
Training	Training Manual Procedures Manual Consultant Qualifications Statement Monitoring Plan
Methodologies	Any Protocols and Emission Factors Used (in addition to the GRP and PUP) Quality Assurance/Quality Control Plans for Continuous Emissions Monitoring Systems
Step 3: Verifying Emission Estimates	
Direct Emissions from Stationary Combustion	FERC Form 1 EIA Forms Fuel Purchase Records Electronic Data Reports Data Acquisition and Handling System Relative Accuracy Test Audit results Accuracy Test Results for Fuel Flow Monitors Fuel Meter Data Fuel Meter Calibration and Maintenance Records Inventory of Stationary Combustion Facilities Electric Generation Data (MWh) Steam Generation Data (Mlbs) Air Permits State and Federal Inventory Reports Any Protocols and Emission Factors Used (in addition to the GRP and PUP)

Direct Emissions from Mobile Combustion	Fuel Purchase Records, Fuel in Stock, Vehicle Miles Traveled, Inventory of Vehicles, Any Protocols and Emission Factors Used (in addition to the GRP)
Direct Emissions from Process Activities	SO_2 Scrubber installation and operation records Calcium Carbonate Purchase Records Any Protocols and Emission Factors Used (in addition to the GRP and PUP)
Direct Fugitive Emissions from Electricity Transmission and Distribution	State and Federal Inventory Reports EPA SF_6 Annual Reporting Form Transmission/Substation Maintenance and Installation Logs SF_6 Purchase, Sales and Recycling Records, SF_6 Activity Logs Any Protocols and Emission Factors Used (in addition to the PUP)
Direct Fugitive Emissions from Air Conditioning and Refrigeration Systems (Stationary and Mobile)	Refrigerant Purchase Records Refrigerant Sales Records Any Protocols and Emission Factors Used (in addition to the GRP)
Direct Fugitive Emissions from Fire Suppression Equipment	Fire Suppression Purchase Records Refrigerant Sales Records Any Protocols and Emission Factors Used (in addition to the GRP)
Direct Fugitive Emissions from Handling and Storage of Solid Fuels	Coal Purchase Records Biomass Purchase Records Any Protocols and Emission Factors Used (in addition to the PUP)
Indirect Emissions from Electricity Transmission and Distribution Losses	FERC Form 1 Wholesale Power Purchases and Sales Records Wheeling Records Direct Access Records Total Receipts and Delivery of Electricity to Consumers Any Protocols and Emission Factors Used (in addition to the PUP, e.g., Line Loss Values)
Indirect Emissions from Electricity Use	Monthly Electric Utility Bills Emission Factors (if not default)
Indirect Emissions associated with Cogeneration	Monthly Utility Bills Fuel and Efficiency Data from Supplier Emission Factors (if not default)
Indirect Emissions associated with Imported/Exported Steam	Monthly Utility Bills Fuel and Efficiency Data from Supplier Emission Factors (if not default)
Indirect Emissions associated with District Heating	Monthly Utility Bills Fuel and Efficiency Data from Supplier Emission Factors (if not default)
Indirect Emissions associated with District Cooling	Monthly Utility Bills Fuel and Efficiency Data from Supplier Emission Factors (if not default)

Step 1: Identifying Emission Sources

Certifiers should review each power/utility participant's reported emission source inventories (facility, source, and fuel) to ensure that all significant sources are identified. Certifiers should then determine the GHGs that will result from the identified sources and estimate their magnitude. GHGs that are not required to be reported can be disregarded. Finally, certifiers should rank by the total annual emissions the remaining reported emissions by CO_2e to assess the environmental risk associated with the emissions.

When the emission source inventory is complete, certifiers should review the power/utility participant's GHG Emission Report and document answers to the following questions, to assess if the GHG Emission Report in CARROT reflects the geographic, organizational, and operational scope of the power/utility participant:

1. Does the GHG Emission Report include all non *de minimis* facilities and sites under the ownership or management control of the participant?

2. Does the report include all non *de minimis* sources of GHG emissions within the geographic and organizational boundaries of the participant?

3. Does the report include all applicable types of GHGs from each emission source within the geographic and organizational boundaries of the participant?

4. Has the participant specified a baseline or baselines?

    a. If so, have any mergers, acquisitions, or divestitures occurred during the current reporting year?

    b. Have any significant activities been outsourced in the current year?

    c. If so, has the baseline been adjusted to reflect any structural changes?

After these questions have been answered, certifiers will be able to determine if the GHG Emission Report accurately reflects the geographic, organizational, and operational scope of the participant.

The following tables provide a listing of potential sources from the power/utility sector. This information is also included in the Power/Utility Certification Activities Check List.

Table 2. List of Sources within Power/Utility Sectors

Stationary Sources

Technology	Source Type
Boilers	Natural Gas Boilers, Residual or Distillate Oil Boilers, Coal-fired Boilers (pulverized coal, fluidized bed, spreader stoker, tangentially fired, wall fired, etc.), Biomass-fired Boilers, Dual-fuel Fired Boilers, Auxiliary Boilers, etc.
Turbines	Combined Cycle Gas, Simple Cycle Gas, Combined Heat and Power, Microturbines, Steam Turbines, Integrated Gasification Combined Cycle, etc.
Internal Combustion Engines	Emergency and Backup Generators, Reciprocating Engines, Compressors, Firewater Pumps, Black Start Engines, etc.
Flares	Landfill Gas, Waste Gas, etc.
Other	Fuel Cells, Geothermal, Anaerobic Digesters, Refuse-derived Fuels, etc.

Fugitive SF_6 Sources

Segment	Equipment
Electricity Transmission	Circuit Breakers, Current-Interruption Equipment, Transmission Lines, Transformers, Substations
Electricity Distribution	Circuit Breakers, Current-Interruption Equipment, Distribution Lines, Transformers, Substations

Other Fugitive Emission Sources

Segment	Facilities	Source	Fugitive Emissions
Solid Fuel Handling and Storage	Electric Generation Facilities, Fuel Storage Facilities	Coal Piles, Biomass Piles	CH_4
Stationary and Mobile Cooling and Refrigeration	Electric Generation Facilities, Office Buildings, Mobile Sources	Air Conditioning and Refrigeration Systems	HFCs
Fire Extinguishers	Electric Generation Facilities	Total Flooding Fire Extinguishing Systems	HFCs

Indirect Emissions Sources (T&D Losses)

Segment	Facilities	Equipment
Electricity Transmission	Feeders and Transmission Lines	Conductors
Electricity Distribution	Distribution Systems and Substations	Transformers

Indirect Emissions Sources (Purchased Electricity, Heat, Steam, and Cooling for Own Consumption)

Segment
Electricity use in office buildings and other sites.
District cooling use in office buildings and other sites.
District heating use in office buildings and other sites.
Cogeneration use in office buildings and other sites.
Imported steam in office buildings and other sites.

Once you have identified and reviewed all emission sources, please proceed to Step 2 to review the calculation methods used and the management systems employed.

Step 2: Reviewing GHG Management Systems and Estimation Methodologies

After the scope and comprehensiveness of the participant's emission sources has been confirmed, certifiers should review the methodologies and management systems that the participant used to calculate their emissions.

This is principally a risk assessment exercise, in which the certifier must weigh the relative complexity of the scope of the participant's emissions, the participant's

methodologies and management systems used to prepare the GHG Emission Report, and the risk of calculation error as a result of reporting uncertainty or misstatement. Through these steps, the certifier should determine the appropriateness of the management systems to provide required data to the Registry.

A certifier's **general review of a participant's GHG management systems** should document answers to the following questions:

1. Are calculation methodologies/procedures used to manage GHG emissions data at the unit and/or the facility level?
2. Are the methodologies/procedures appropriate given the uncertainty and the relative quantity of $CO2_e$ associated with the emissions?
3. Are these methodologies/procedures standard within the power/utility industry as stipulated in 40 CFR Part 75?
4. Are methods used to manage and implement entity-wide GHG emissions reporting programs appropriate for the size and complexity of the organization?
5. If the participant has more than one facility, are the emissions data correctly aggregated at the entity level?
6. Is an individual responsible for managing and reporting GHG emissions? Is this individual qualified to perform this function?
7. Is appropriate training provided to personnel assigned to GHG emissions reporting duties?
8. If the participant relies on external staff to perform required activities, are the contractors qualified to undertake such work? Is there internal oversight to assure quality of the contractor's work?
9. Are appropriate documents created to support and/or substantiate activities related to GHG emissions reporting activities, and is such documentation retained appropriately? For example, is such documentation maintained through reporting plans or procedures, fuel purchase records, etc.?
10. Are the mechanisms used to measure and review the effectiveness of GHG emissions reporting programs appropriate for this purpose? For example, are policies, procedures, and practices evaluated and updated at appropriate intervals?

Certifiers should also consider how participants' management systems are designed to support reporting five categories of emission sources (indirect, mobile, stationary, process and fugitive). Consequently, in reviewing a participant's Total Emissions Report, certifiers should document answers to the following questions:

1. Does the management system capture the diversity of the sources that comprise each emission category? For example, are there multiple types of electric generating sources and other stationary combustion sources that require different emission estimation methodologies?

2. Does the system capture all the GHGs emitted from each emission source category?
3. Has the participant used the emission factors and standardized estimation methods in the Registry's Power/Utility Protocol to calculate emissions in each source category?
    a. If not, has the participant or its technical assistance provider developed estimation methods independently?
    b. If the participant uses alternative emission factors, are they documented and explained appropriately?
    c. Are these acceptable to the certifier and Registry?
4. Does the participant's GHG management system appropriately track emissions in all of the emission source categories?

Once the certifier has assessed the overall risk of misstatement associated with the management systems, those risks should be assessed in conjunction with the weighted CO_2e estimates determined in Step 1 (Identifying Emission Sources).

Certifiers should then identify the areas with the greatest potential for material misstatements (either based on volume of emissions, lack of management systems, or both) to determine the best risk-based strategy to identify a representative sample of emissions to recalculate in Step 3 below.

Step 3: Verifying Emission Estimates

The final step in completing the core certification activities is to verify the emission estimates. To do so, you will re-calculate a subset of the power/utility entity's emissions and compare your calculated results from this sub-sample with the power/utility entity's calculated results from the same sources to determine if the GHG emissions inventory is free of material misstatements. Based on a participant's identified emission sources, management systems, and corresponding risk profile of GHG emissions, certifiers should select a representative sample of calculations to verify and sites to visit. Sampling procedures may entail conducting site visits, but should include reviewing documents such as fuel purchase records or emissions monitor results, and recalculating emission estimates based on underlying activity data.

This Step is principally a risk assessment exercise, in which you must weigh the relative complexity of the scope of and diversity of the power/utility entity's GHG emissions, the appropriateness of a power/utility entity's calculation methodologies and GHG management systems used to prepare the annual inventory report, along with the risk of calculation or reporting error to determine the best risk-based strategy to identify a representative sample to sample and re-calculate. You must compare your emissions data and calculations to the power/utility entity's emissions data and calculations for the same sources.

To finish Step 3, you must complete the following tasks:

1. Assess the areas of greatest impact and uncertainty in the emissions profile.
2. Select a representative sample of data to recalculate and sources to visit.
3. Develop and implement a strategy to recalculate the GHG emissions and visit the

sources in the sample.

4. Assess the power/utility entity's data collection.
5. Compare your estimated GHG emissions to those of the power/utility entity to determine if any material misstatements exist.

2.1 Documentation

When assessing the participant's reported emissions, you will review a number of corporate documents, including invoices, purchases, financial reports, and regulatory filings to ascertain the validity of the reported information. As part of your recalculation, you should compare information from multiple sources to verify the accuracy of significant data points. For instance, to identify an entity's complete inventory, you could compare e.g., their permitting information, their corporate annual report and information reported on their website, to determine if the complete inventory of sources has been reported.

The power/utility sector already reports entity-level assets, operational, financial and emissions data to local, state and federal agencies. These reports are third party audited and verified by the receiving agencies. For purposes of the PUCP, certifiers can accept that data taken from previously audited reports, including FERC, SEC, U.S. EPA, CPUC and AQMD filings, is correct. However, certifiers should verify that data has been transferred into the CARROT correctly, and also review the participant's operations to ensure that the meters and sensors that collect data reported to these agencies are properly maintained and functioning.

2.2 Certifying Emissions from CEMs

For participants reporting CO_2 emissions from their stationary combustion sources using CEMs under 40 CFR Part 75, at your discretion, you may review CEMs specific Monitoring Plans, CEMs specific QA/QC Plans, CEMs specific maintenance records, Data Acquisition and Handling System (DAHS), and Relative Accuracy Test Audits (RATA) as you certify the participant's GHG inventory.

If you are uncertain of the accuracy of the CEMs data, you may cross-check this data with the CO_2 emissions based on total fuel use calculations. In any instance where a participant's CO_2 emissions reported from CEMs data differs significantly (greater than 10%) from that calculated from fuel use, this may constitute a material misstatement. As such, if you complete the CEMs to fuel based calculation cross check and the values differ by greater than 10%, then you should investigate the cause and request that the entity correct the misstatement prior to certifying the inventory.

2.3 Conducting Site Visits

In Table 3, below, the Registry recommends the minimum number of facilities that should be visited based on the size of the entity. A facility is considered all buildings and operations located at the same mailing address. However, participants also have some flexibility in how they can define a facility. The certifier should use professional judgment to assess the number of visits needed, and the appropriateness of the participant's classification and description of its facilities.

Table 3. Recommended Minimum Number of Facilities to Be Visited Based on Participant Size

Total Facilities	Minimum Sample Size
2-10	30%
11-25	20%
26-50	15%
51-100	10%
101-250	5%
251-500	3%
501-1,000	2%
Over 1,000	1-2%

2.4 Questions to Consider in Verifying Emissions Estimates

A certifier's verification of emissions estimates should document the answers to the following questions:

1. Is the reported total stationary fuel use by fuel type consistent with the fuel use records?

2. Is the reported total consumption of fuels in motor vehicles consistent with available documentation and by vehicle type? If the entity calculates transportation emissions based on vehicle mileage, is the reported vehicle mileage consistent with vehicle mileage records?

3. Are the reported process and fugitive emissions consistent with activity data, maintenance records, or purchase and sales records?

4. Are the emission factors used by the participant appropriate? If Registry default factors are not used, do the alternative emission factors provide increased accuracy? Is their derivation and explanation of increased accuracy properly documented and reasonable?

5. Are the reported electricity, steam, and district heating and cooling use consistent with utility bills?

6. Does a sample of the participant's calculations agree with your re-calculated direct (mobile, stationary, process & fugitive) & indirect emissions estimates?

7. Does the participant use an approved CEMs configuration?

8. Is this the first year that a participant is reporting CO_2 emissions to the Registry using CEMs?
    a. If so, does the fuel based calculations corroborate the CO_2 emissions reported?

9. Has the CO_2 emission rate (lbs CO2/MWh) changed by 10% or more from the previous year at a unit that CEMs is used to report emissions?
    a. If so, does the fuel-based calculations corroborate this change?

10. Have you documented your process for determining the appropriate sampling plan?

11. Have you performed data triangulations where reasonable?

12. Are all significant GHG emissions included? Are all emissions that are considered de minimis emissions documented as such?

13. Are the current year's reported emissions significantly different from the prior year's emission levels? If so, do you understand the reasons for the changes, and to the best of your knowledge, do they explain the differences in emissions?

14. Has the accumulated change in reported emissions, since the last baseline update, changed by more than ten (10) percent? If so, has the baseline, if any, been recalculated?

15. Are any discrepancies between your emissions estimates and the participant's material? If so, have you addressed those discrepancies with the participant? Has the Total Emissions Summary in CARROT been adjusted and reviewed?

2.5 Finishing the Certification Process

Upon completion of these activities, you should follow the remaining steps in the certification process, as detailed in the General Certification Protocol.

Power/Utility Entity Inventory Certification Activities Log		
Preparing for Certification	**Date Achieved**	
Request determination of COI from CEC		
Notify CEC and Registry of Planned Certification Activities		
Conduct Kick-off Meeting With Power/Utility Entity		
Plan Certification Activities Based on Power/Utility Entity Characteristics		
Core Certification Activities **Step 1: Identify Potential Emission Sources**	**Date Achieved**	
Review and confirm the entity's GHG emissions inventory includes all required sources and meets the Registry's standards direct (stationary, mobile, fugitive, and process) and indirect (purchased and consumed electricity, steam and heat and T&D losses).		
Review & confirm the power/utility entity's geographic boundaries.		
Review & confirm the power/utility entity's organizational boundaries (review ownership & reporting scope).		
Confirm the power/utility entity's reporting responsibility (classified under one or more NAICS codes).		
Check state and federal records to determine all key sources of the entity are included.		
If a baseline is specified:		
Assess if any structural changes occurred within the entity.		
Determine if emission sources have changed.		
Questions	**Yes**	**No**
1. Does the GHG Emission Report include all significant emissions from all direct and indirect emissions sources by the entity within the state of California, including:		
Stationary Sources: Boilers, turbines, internal combustion engines, flares, and other?		
Fugitive SF_6 Sources: • Electricity transmission: Circuit breakers, current-interruption equipment, transmission lines and transmission substations? • Electricity distribution: Circuit breakers, current-interruption equipment, transmission lines and transmission substations?		
Other Fugitive Emission Sources: from fuel handling and storage, stationary and mobile cooling and refrigeration?		
Indirect Emission Sources associated with T&D Losses: feeders and transmission lines, distribution systems and substations?		
Indirect Emission Sources associated with Purchased Energy: electricity, steam, heating and cooling bills ?		
2. Does the report include all significant GHG emissions from each of the required sources within the geographic and organizational boundaries of the power/utility entity?		
3. Have any mergers, acquisitions, or divestitures occurred during the current reporting year?		
4. Have any activities been outsourced in the current year? If a baseline has been set, has it been adjusted accordingly?		
2. Review Methodologies and Management Systems	**Date Achieved**	
Review the power/utility entity's GHG management plans.		
If the power/utility entity has established an entity baseline, review the baseline assumptions and confirm the appropriateness of the baseline.		
Review the power/utility entity's quantification methodologies and emission factors and confirm they meet the Registry's criteria, and assess its appropriateness		
Review the power/utility entity's monitoring and measurement methodologies, confirm it meets the Registry's criteria, and assess its appropriateness		

Evaluate GHG Personnel Training and ability to prepare the Annual Emission Report	

Questions	Yes	No
5. Does the power/utility entity have an appropriate management plan for each primary activity?		
6. Are appropriate methods used to manage and implement entity-wide GHG emissions reporting programs?		
7. Is the power/utility entity's emissions data correctly aggregated and monitored?		
8. Is a qualified individual responsible for managing and reporting GHG emissions?		
9. Is appropriate training provided to personnel assigned to GHG emissions reporting duties? If the power/utility entity relies on external staff to perform required activities, are the contractors' qualified to undertake such work?		
10. Are appropriate documents created to support and/or substantiate activities related to GHG emissions reporting activities, and is such documentation retained appropriately?		
11. Are appropriate mechanisms used to measure and review the effectiveness of GHG emissions reporting programs? For example, are policies, procedures, and practices evaluated and updated at appropriate intervals?		
12. Does the power/utility entity have a sound annual data gathering system in place to provide accurate data for the entity's annual report?		
13. Has the power/utility entity used the Registry's default calculation methodologies to calculate emissions in each source category?		
13a. If power/utility entity uses alternative calculations, are they documented and explained appropriately? Do they meet the Registry's criteria for accuracy and precision?		
14. Have any activities been outsourced in the current year? If a baseline has been set, has it been adjusted accordingly?		
15. Has the power/utility entity used the Registry's default emission factors to calculate emissions in each source category?		
15 a. If power/utility entity uses alternative emission factors are they documented and explained appropriately? Do they meet the Registry's criteria for accuracy and precision?		

3. Verify Emission Estimates	Date Achieved	
Create a risk-based sampling method to directly sample power/utility entity's sources		
Survey a sub sample of sources by area:		
Direct Stationary Combustion Emissions		
Direct Mobile Combustion Emissions		
Direct Fugitive Emissions		
Direct Process Emissions		
Indirect Emissions from T&D Losses		
Indirect Emissions from Purchased and Consumed Electric, Heat and Steam		
Compare your results from your sub-samples with the power/utility entity's results using the methodologies and emissions factors and determine if any material misstatements exist		

Questions	Yes	No
16. Did you survey the sources described by the power/utility entity to confirm the accuracy of their descriptions?		
17. Does your certification sampling methodology account for the diversity of sources and activities within the power/utility entity?		
18. Total number of power/utility entity sources by category:_____ Total number of sources by category sampled:_____		

19. Are the reported emissions calculations accurate (within 5% of an independent calculation?)		
20. Does the participant have approved CEMs Monitoring Plans, Data Acquisition and Handling Systems, QA/QC Plans, Relative Accuracy Test Audit Results?		
21. Is this the first year that a participant is reporting CO2 emissions to the Registry using CEMs? a. If so, does fuel-based calculations corroborate the results?		
22. Has the CO2 emission rate (lbs CO2/MWh) changed by 10% or more from the previous year at units that report using CEMs? a. If so, does fuel-based calculations corroborate the results?		
23. If your sampling results differed by more than 5% from the power/utility entity's, did the power/utility entity adjust their results to be consistent with your findings?		
24. Have you performed data triangulations where reasonable?		
25. Are the current year's reported emissions significantly different from the prior year? If so, are the causes of changes understood by you and reasonable?		
26. Has the accumulated change in reported emissions, since the last baseline update, changed by more than 10%? 27. Has the methodology with which the power/utility entity calculated emissions changed from previous years? a. If so, have previous years been recalculated?		
Completing the Certification Process	**Date Achieved**	
Prepare a Detailed Certification Report & present to power/utility entity		
Complete the Power/Utility Emission Inventory Certification Activities Log & present to power/utility entity		
Prepare a Certification Opinion for the entity's GHG emissions & present to power/utility entity		
Prepare a Certification Opinion for the entity's GHG emissions inventory & present to power/utility entity		
Conduct Exit Meeting with power/utility entity to discuss Certification Report, Opinion, and Logs		
Submit Authorized Certification Opinions and Certification Activities Checklists to the Registry		
Provide Certification Records to Client for Retention		